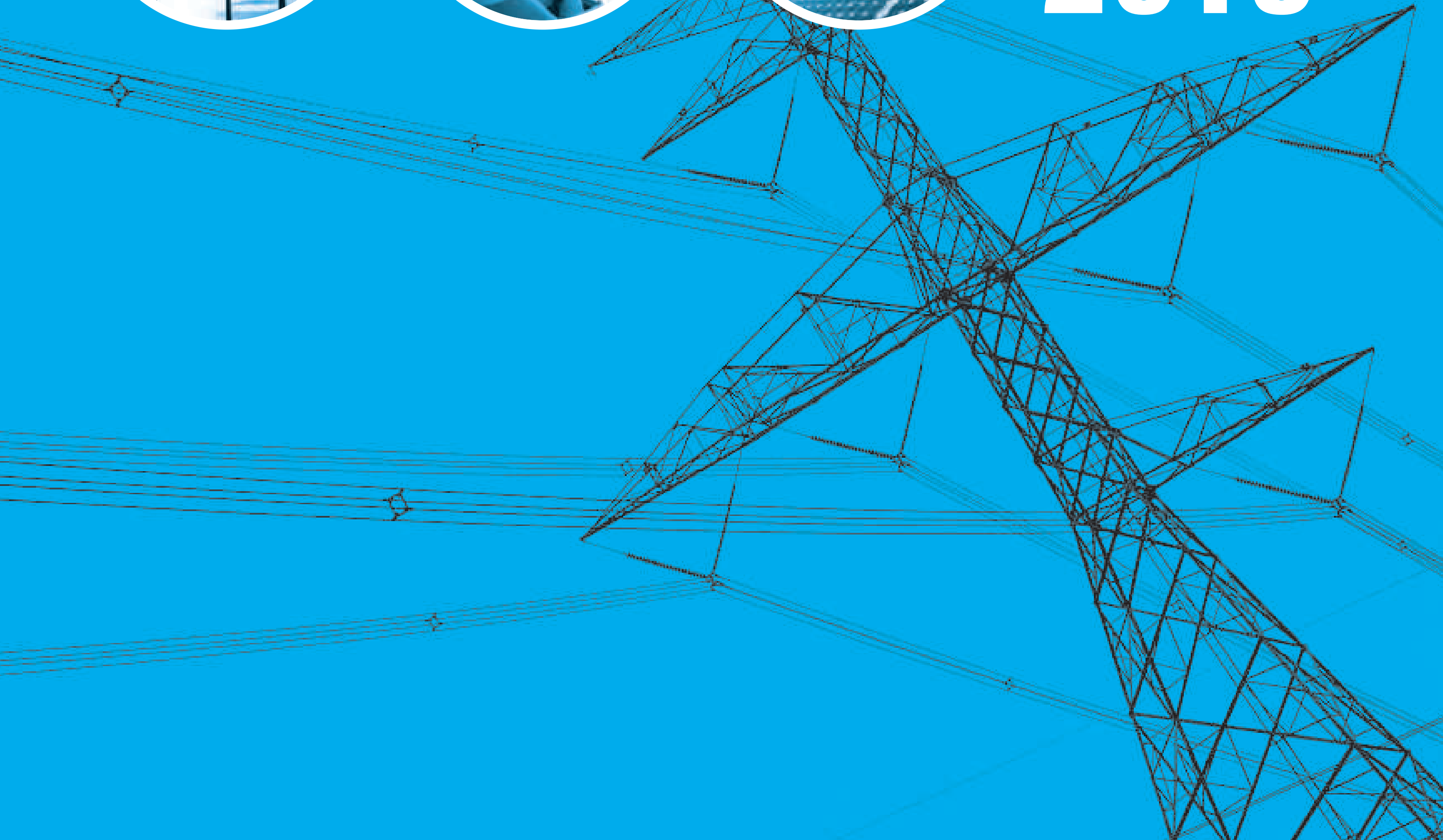
Algonquin Power & Utilities Corp.

# ANNUAL REPORT 2013



# Algonquin Power & Utilities Corp.

Algonquin Power & Utilities Corp. owns and operates a $3.5 billion portfolio of diversified regulated and non-regulated utility assets across North America.

Our vision is clear. To be the utility company most admired by our customers, communities and investors for our people, passion and performance.

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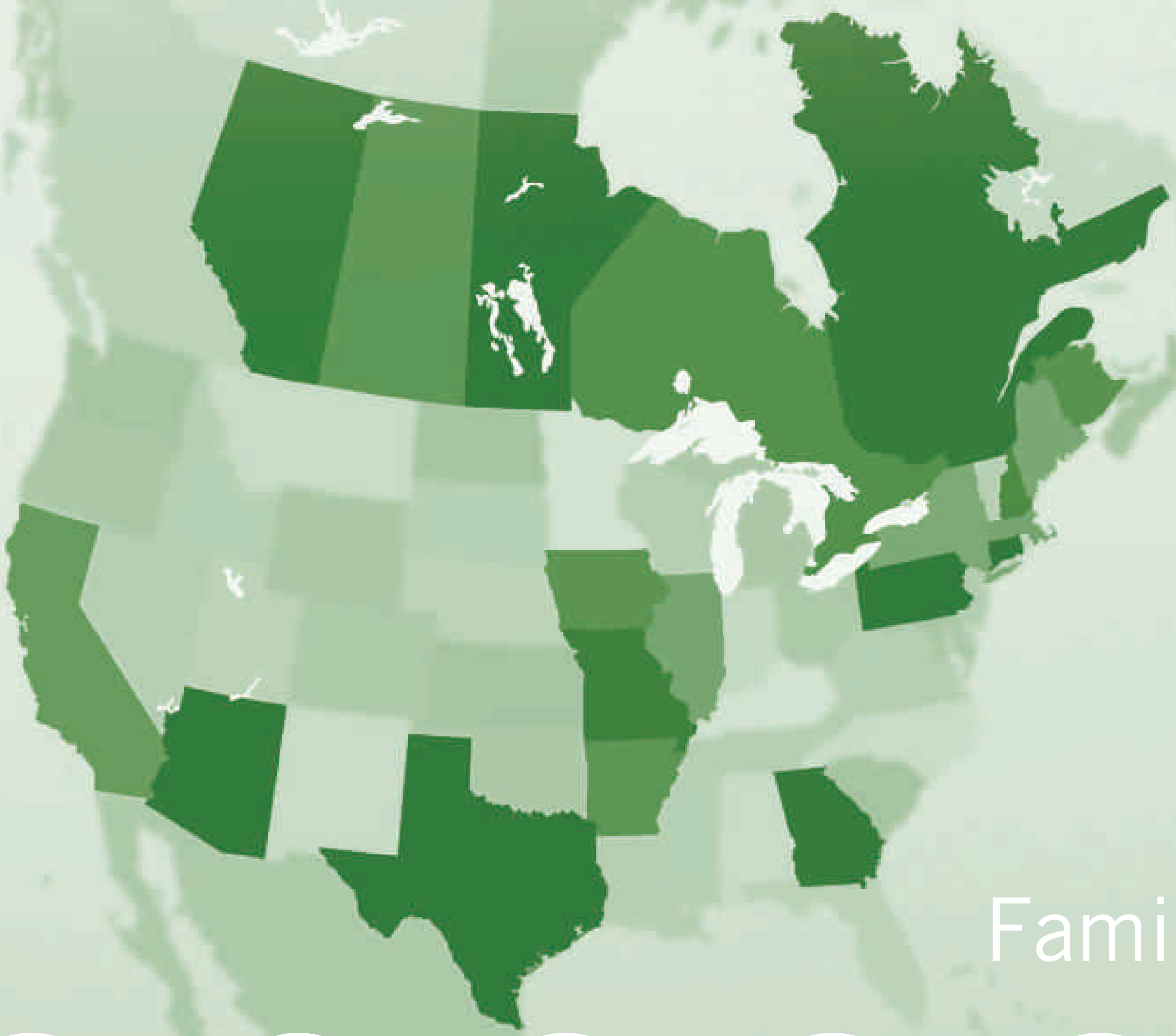
Toronto Stock Exchange: Common Shares - AQN, Preferred Shares - AQN.PR.A, AQN.PR.D

www.AlgonquinPowerandUtilities.com

# AQN at a Glance

## Our diversification by business, geography and modality supports our consistent performance and provides opportunities for growth.



Family

**20**
Provinces and States

**1,185**
Total employees

**1,100**
MW installed capacity

**360**
Wind turbine generators

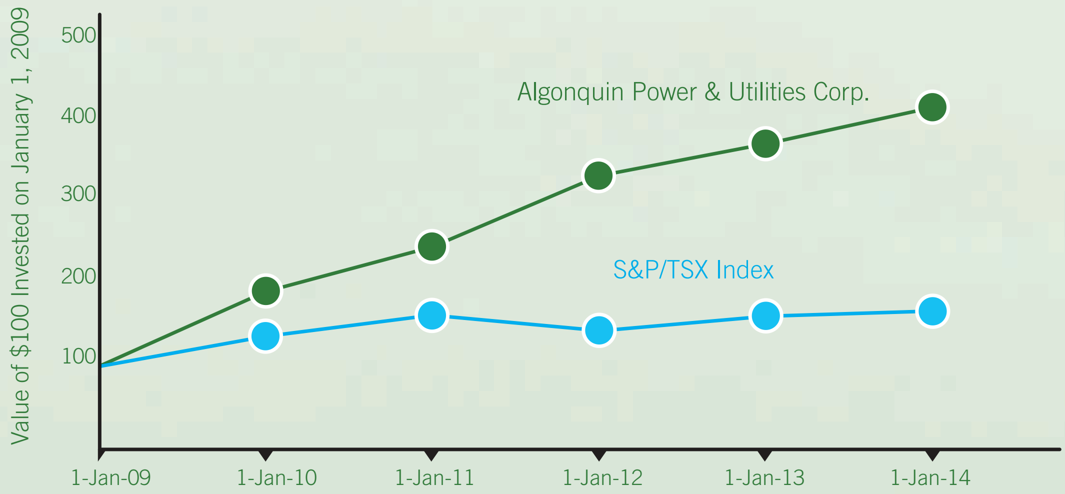
**42,812**
Solar panels

Commitment

Efficiency

Quality

## Total Return Performance




Care

Community

**76**
**Hydroelectric generators**

**470,000**
**Utility customers**

**10,755**
**Km of gas distribution mains**

**1,920**
**Km of electricity distribution lines**

**2,272**
**Km of water distribution mains**

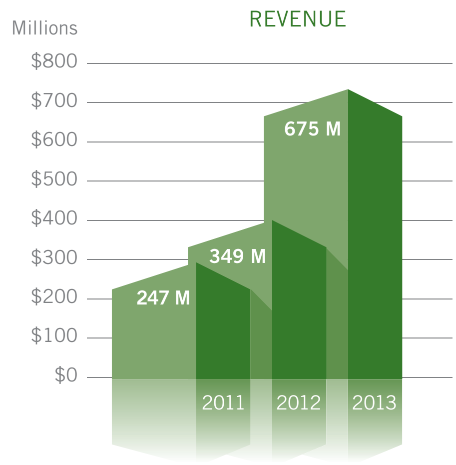
# 2013 By the Numbers

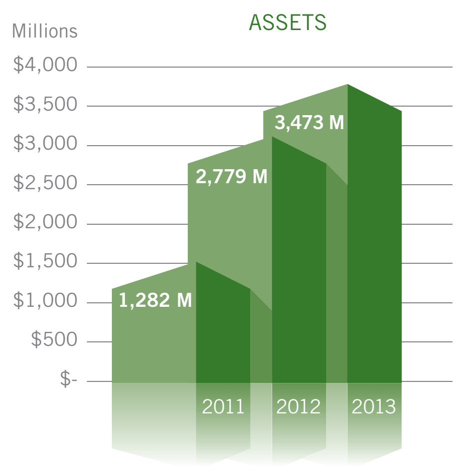
**Annual total shareholder return** — **12.4%**

**Three year compound annual growth rate in adjusted EBITDA[1]:** — **34%**

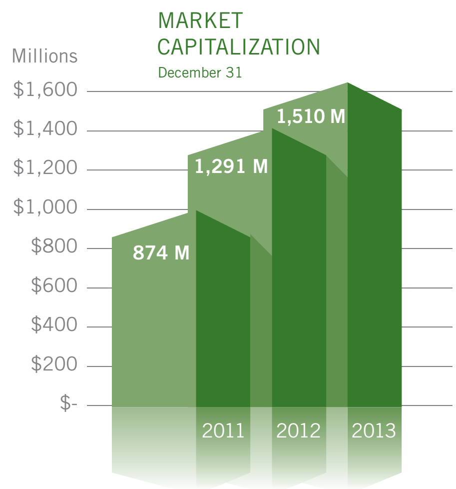
**Three year compound annual growth rate in adjusted net earnings[1]** — **18%**

**Three year compound annual growth rate in adjusted funds from operations[1]** — **34%**




Algonquin Power & Utilities is headed by an experienced executive management team with over 60 years of combined experience in the regulated utility and non-regulated power sectors. We have successfully grown the business over a period of 17 years and now boast annual revenues of over $675 million.



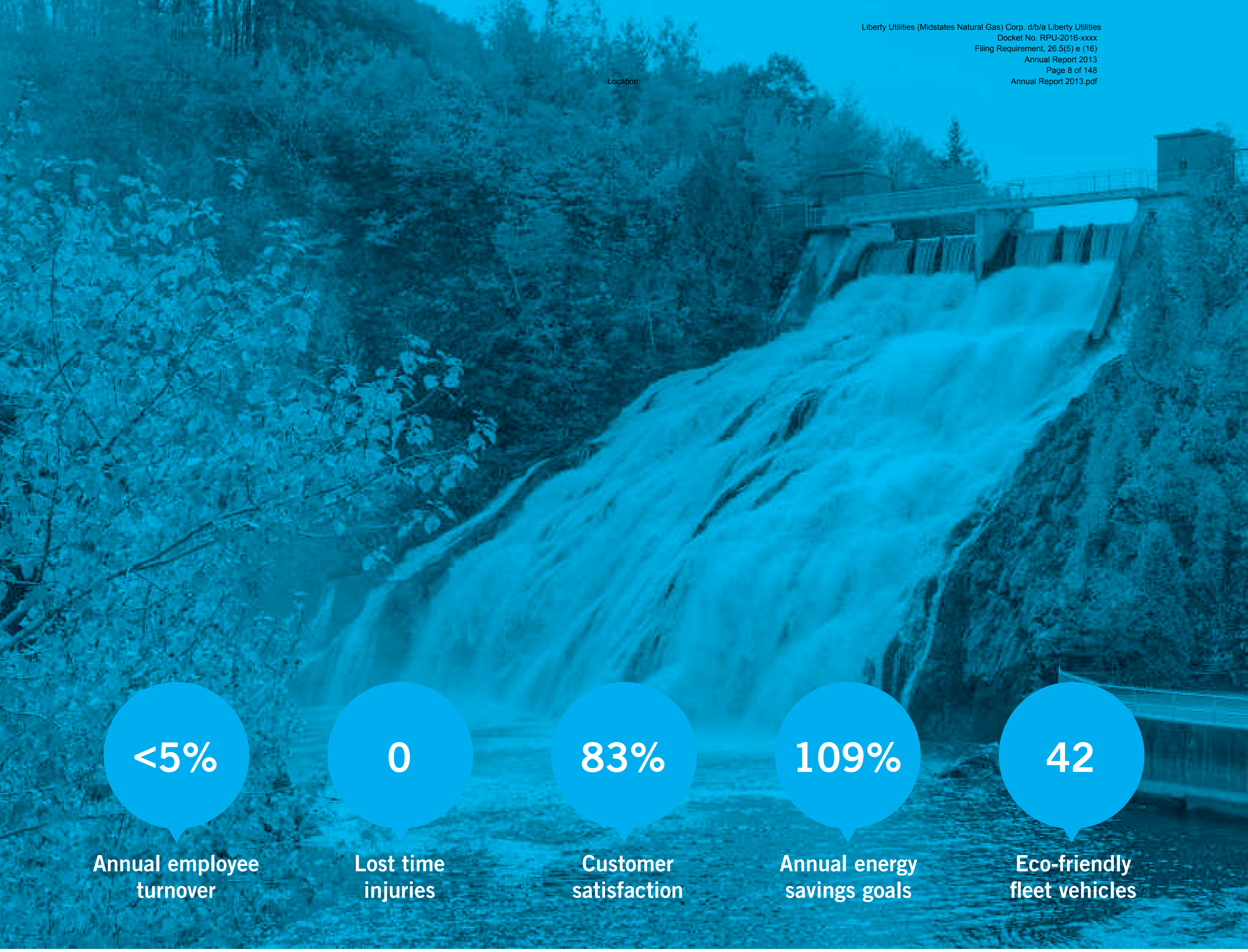
# 2013 Financial Highlights

(in $ millions)

| Revenue | 2013 | 2012 | 2011 |
|---|---|---|---|
| Power | 180.2 | 114.4 | 121.5 |
| Utilities | 485.2 | 230.6 | 122.4 |
| Other | 9.9 | 3.8 | 3.6 |
| **Total Revenue** | **675.3** | **348.8** | **247.5** |
| | | | |
| **Adjusted EBITDA**[1] | **226.9** | **88.1** | **94.4** |
| | | | |
| **Earnings, Funds from Operations and Dividends** | | | |
| Adjusted Funds from Operations[1] | 153.5 | 66.8 | 63.6 |
| Per Share | 0.72 | 0.42 | 0.54 |
| Adjusted Net Earnings[1] | 60.9 | 18.9 | 37.0 |
| Per Share | 0.27 | 0.11 | 0.32 |
| Dividends to Shareholders | 68.3 | 50.2 | 32.4 |
| Per Share | 0.33 | 0.30 | 0.27 |
| | | | |
| **Balance Sheet Data** | | | |
| Total Assets | 3,472.6 | 2,779.0 | 1,282.3 |
| Long-Term Liabilities (includes current portion) | 1,255.6 | 770.8 | 455.0 |
| Number of Shares Outstanding as of Dec. 31 | 206,348,985 | 188,763,486 | 136,122,780 |
| | | | |
| **Property, Plant & Equipment** | | | |
| Canada | 433.2 | 395.9 | 474.1 |
| US | 2,275.6 | 1,690.4 | 446.0 |
| **Total** | **2,708.8** | **2,086.3** | **920.1** |
| | | | |
| **Renewable energy production (% of long term average)** | **95%** | **89%** | **107%** |
| | | | |
| **Utility Connections** | **480,800** | **344,700** | **122,406** |

[1]Non-GAAP Financial Measures

The terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization", and "adjusted funds from operations" (together, the "Financial Measures") are used throughout this Annual Report. The Financial Measures are not recognized measures under GAAP. There is no standardized measure of the Financial Measures, consequently APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of these Financial Measures can be found in the Management Discussion & Analysis section of this Annual Report.




# Leading in Corporate Responsibility

Our vision is to be the utility company most admired by customers, communities and investors for our people, passion and performance. We will achieve this vision through our robust strategy for growth, a passionate workforce and by continuing to run our businesses in a responsible manner. As a leader in the North American utility industry, Algonquin Power & Utilities plays an important role in its commitment to environmental, social, and economic sustainability.

Over our 17 year history, Algonquin Power & Utilities has grown to a family of over 1200 valued employees through a culture of core values, ownership and empowerment within our regional operations, where community ties, local knowledge and reliability matters most. Our company prides itself on the

# Carbon Disclosure Project participant since 2008

acquisition and development of assets built for the long-term, and thrives because of the dedication, care and commitment of our employees. During our history we have become a leader in Corporate Responsibility.

To execute on our vision, we embrace all industry best practices, and will be publishing our first Corporate Responsibility report on our website in the coming months, with the Global Reporting Initiative (GRI) framework guiding our journey, and more specifically using the GRI G4 Guidelines to shape our first report.

Corporate Responsibility is about the interrelationship between stakeholder value and financial performance. We acknowledge that our business must create value for our shareholders but we further believe that we must deliver value to all of our stakeholders and not just our shareholders. Our belief is that when relations with all stakeholders are solid, our business thrives, risks are reduced and returns are increased.

As we share our organization's economic, social and environmental footprint, we believe you'll agree that we have always, and will continue, to create value for all of our stakeholders.

**Ian Robertson**
CEO

**Ken Moore**
Chairman of the Board of Directors

# Shareholder letter

Dear Fellow Shareholders,
Our vision of being the utility company most admired by customers, communities and investors for our people, passion and performance, has helped guide Algonquin Power & Utilities to deliver strong shareholder returns and has positioned the company well to provide future growth.

The 2013 financial results are evidence that last year was transformative for the company; the positive financial impact of a number of completed acquisition and expansion initiatives has re-affirmed our growth trajectory. Algonquin Power & Utilities is well positioned to continue expansion of both our non-regulated electrical generation and regulated utility distribution businesses across North America well into 2014 and beyond.

## A Year of Growth

In 2013, we outlined our plan to maintain the growth momentum Algonquin Power & Utilities has experienced over the past few years. Our 2013 scorecard targeted additional earnings contributions from new businesses, growing discretionary cash flow and a strengthened base of stable earnings. Value accretive growth through organic expansion, greenfield power project development and attractive acquisitions were also highlighted as objectives for the year. We hope you agree that the 2013 results demonstrate delivery against these objectives.

**Algonquin Power Co**.

In our non-regulated electrical generation division, we announced several exciting growth initiatives including the acquisition of the remaining 40% interest in a portfolio of 400 MW of U.S. based wind generation; as majority owner and operator of these projects, we were a natural fit for this investment. In addition, last year saw a full year contribution from the 109.5 MW Shady Oaks wind farm acquired in early January 2013.

During 2013, we confirmed our belief that solar electrical generation will play an increasingly significant role in the North American energy solution: falling equipment prices, improving efficiencies, low annual production volatility and strong regulatory support are all expected to contribute to a bright future for this form of generation in the coming years. We were pleased that 2013 saw the construction of our first 10 MW solar powered electrical generation plant near Cornwall, Ontario, and we announced our commitment to developing the 20 MW solar generation project near Bakersfield, California in 2014, further diversifying our portfolio of generating assets.

**Liberty Utilities Co.**

Within our regulated utilities group, 2013 saw a significant expansion of our operations in the United States. We completed the acquisition of gas distribution utilities in Massachusetts and Georgia, a water utility in Arkansas, and the remaining 49% ownership in our California electricity distribution utility, representing an investment of over $240 million in our utility portfolio. The additional 135,000 utility customers comprising these acquisitions have helped our total connection count move closer to our objective of one million customers by 2018. Our transition team is busy working on the continuing integration activities of these new utilities.

In addition to the financial returns from our significant acquisition program, we have delivered increased earnings in 2013 through continued investment in our existing utility assets. The expanded capital investment in our operations has been the basis of rate increase requests totaling over $29 million across our utility portfolio. We look forward to keeping you up to date on these proceedings throughout the year.

"Our vision of being the utility company most admired by customers, communities and investors for our people, passion and performance, has helped guide us to deliver strong shareholder returns."

## Strong Capital Structure

As you would expect, our growth over the past years and the expectation of a continued growth trajectory for the foreseeable future mandates a measured approach to managing our capital structure and sources of financing.

We believe that a conservative capital structure, a disciplined approach to controlling risk across our businesses and an effective corporate governance structure were key elements in the award by Standard & Poor's of an upgraded BBB (stable) credit rating for the Algonquin Power & Utilities family in 2013. This credit rating upgrade has provided a material reduction in the interest costs associated with our financing initiatives including the $140 million in private placement debt issuances for Liberty Utilities, the $200 million private placement debt financing for Algonquin Power Co. and, most recently, the $100 million preferred share issuance by APUC.

Our relationship with Emera, our largest shareholder, remains strong and they continue to fully support our growth plans. During 2013, the company issued 15.2 million shares to Emera for total proceeds of $90.5 million, bringing their ownership in our company to the 25% maximum contemplated in our strategic investment agreement. We believe that our strong relationship with Emera provides strategic business development support and is an efficient way to raise equity to fund growth.

## Financial Success

We hope you agree that last year's financial results are evidence of the successful execution against our financial and growth strategies; our asset base expanded by 25%, annual revenues grew by 94% and market capitalization increased by almost 17%, all over 2012 results. Perhaps more importantly, the company delivered attractive total shareholder returns of over 12%.

During the year, supported by the earnings and cash flows provided from accretive growth initiatives in both the regulated and non-regulated utilities businesses, the Board of Directors approved a ten percent dividend increase to $0.34 per common share annually. We believe this dividend increase is consistent with our strategy of delivering total shareholder return comprised of an attractive dividend yield and capital appreciation founded on increased earnings and cash flows.

## Plans for 2014

In both our regulated distribution utility and non-regulated power generating businesses, our teams are continuing to actively source and evaluate additional growth opportunities.

Within Algonquin Power Co., we believe that solar generation will represent an increasingly significant component of our generation portfolio and we expect to have 30 MW of solar generation operational by the end of the year. In the wind sector, 2014 will see the commencement of construction of 50 MW of new projects in Quebec and Saskatchewan and the continuing development of 250 MW of additional contracted wind generation projects scheduled for construction in the next couple of years.

"The more than half a billion dollars we invested in new business assets has not only delivered the expected financial returns but has positioned the organization well to deliver continued strong growth in earnings and cash-flows."

On the regulated utilities side of the business, 2014 will see continued investment against the $1 billion pipeline of identified organic growth opportunities. We will maintain our pursuit of additional acquisition opportunities within the water, gas and electric distribution sectors as well as advance investment opportunities in regulated generation and transmission within our existing California electricity distribution utility.

As always, the economics of new growth opportunities will continue to be evaluated against the benchmark of providing increased per share earnings and cash flow to the organization; we will maintain a commitment to delivering value accretive growth in both our non-regulated and regulated utility businesses.

"Our team of professionals consistently work very hard to earn and maintain the confidence of our investors and we can assure you that creating long-term value for your investment is foremost in the decisions we make every day."

## In Summary

We believe that the more than half a billion dollars Algonquin Power & Utilities invested in new business assets has not only delivered the expected financial returns but has also positioned the organization well to deliver continued strong growth in earnings and cash-flows. We remain committed to exploiting the pipeline of over $2.0 billion in identified opportunities in our power and utilities businesses over the coming years. Our Board of Directors continues to provide valuable governance and oversight of the company in reviewing and balancing the many opportunities that come our way.

On behalf of everyone at Algonquin Power & Utilities, we would like to thank you for your continued confidence and support, and confirm our commitment to creating long-term value for your investment.

Sincerely,

Ian Robertson
Chief Executive Officer

Ken Moore
Chairman of the Board of Directors

# Management Discussion & Analysis

(All monetary amounts are in thousands of Canadian dollars, except per share amounts or where otherwise noted.)

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2013. The Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2013 and 2012. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of March 28, 2014.

# Caution concerning forward-looking statements and non-GAAP Measures

## Forward-looking statements

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "anticipates", "believes", "continues", "could", "expect", "estimates", "intends", "may", "outlook", "plans", "project", "strives", "will", and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require APUC to make assumptions and involve inherent risks and uncertainties. APUC cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy; and the state of the Canadian and the United States ("U.S.") economies and accompanying business climate. APUC cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements. In addition, such statements are made based on information available and expectations as of the date of this MD&A and such expectations may change after this date. APUC reviews material forward-looking information it has presented, not less frequently than on a quarterly basis. APUC is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

## Non-GAAP Financial Measures

The terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA"), "adjusted funds from operations", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales", and "net utility sales", are used throughout this MD&A. The terms "adjusted net earnings", "per share cash provided by operating activities", "adjusted funds from operations", "per share cash provided by adjusted funds from operations", Adjusted EBITDA, "net energy sales" and "net utility sales" are not recognized measures under GAAP. There is no standardized measure of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales", and "net utility sales" consequently APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales" and "net utility sales" can be found throughout this MD&A. Per share cash provided by operating activities is not a substitute measure of performance for earnings per share. Amounts represented by per share cash provided by operating activities do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

## Use of Non-GAAP Financial Measures

Adjusted EBITDA

EBITDA is a non-GAAP metric used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of (as applicable): depreciation and amortization expense, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange, earnings or loss from discontinued operations and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the company. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

Adjusted net earnings

Adjusted net earnings is a non-GAAP metric used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses or litigation expenses and are viewed as not directly related to a company's operating performance. Net earnings of APUC can be impacted positively or negatively by gains and losses on derivative financial instruments, including foreign exchange forward contracts, interest rate swaps and energy forward purchase contracts as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funding requirements. APUC uses adjusted net earnings to assess its performance without the effects of (as applicable): gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, litigation expenses and write down of intangibles and property, plant and equipment, earnings or loss from discontinued operations and other typically non-recurring items as these are not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP.

Adjusted funds from operations

Adjusted funds from operations is a non-GAAP metric used by investors to compare cash flows from operating activities without the effects of certain volatile items that generally have no current economic impact or items such as acquisition expenses and are viewed as not directly related to a company's operating performance. Cash flows from operating activities of APUC can be impacted positively or negatively by changes in working capital balances, acquisition expenses, litigation expenses cash provided or used in discontinued operations. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funding requirements. APUC uses adjusted funds from operations to assess its performance without the effects of (as applicable) changes in working capital balances, acquisition expenses, litigation expenses, cash provided or used in discontinued operations and other typically non-recurring items affecting cash from operations as these are not reflective of the long-term performance of the underlying businesses of APUC. APUC believes that analysis and presentation of funds from operations on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of cash flows from operating activities as determined in accordance with GAAP.

Net energy sales

Net energy sales is a non-GAAP metric used by investors to identify revenue after commodity costs used to generate revenue where revenue generally is increased or decreased in response to increases or decreases in the cost of the commodity to produce that revenue. APUC uses net energy sales to assess its revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through either directly or indirectly in the revenue that is charged. APUC believes that analysis and presentation of net energy sales on this basis will enhance an investor's understanding of the revenue generation of its businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

Net utility sales

Net utility sales is a non-GAAP metric used by investors to identify utility revenue after commodity costs, either natural gas or electricity, where these commodities are generally included as a pass through in rates to its utility customers. APUC uses net utility sales to assess its utility revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through and paid for by the utility customer. APUC believes that analysis and presentation of net utility sales on this basis will enhance an investor's understanding of the revenue generation of its utility businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

## Overview and Business Strategy

APUC is incorporated under the *Canada Business Corporations Act*. APUC owns and operates a diversified portfolio of regulated and non-regulated generation, distribution and transmission utility assets which deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through a quarterly dividend augmented by share price appreciation arising from dividend growth supported by increasing per share cash flows and earnings.

APUC's current quarterly dividend to shareholders is $0.085 per share or $0.34 per share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities and mitigate the impact of fluctuations in foreign exchange rates. Further increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board") with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC conducts its business primarily through two autonomous subsidiaries: Algonquin Power Co. ("APCo") which owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; and Liberty Utilities Co. ("Liberty Utilities"), a diversified rate regulated utility which owns and operates a portfolio of North American electric, natural gas and water distribution and wastewater collection utility systems.

### Algonquin Power Co.

APCo generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable power generation and clean energy power generation facilities located across North America. APCo seeks to deliver continuing growth through development of new Greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

APCo owns or has interests in hydroelectric facilities with a combined generating capacity of approximately 125 MW. APCo also owns or has interests in wind powered generating stations with a combined generating capacity of 650 MW. Approximately 82% of the electrical output from the hydroelectric and wind generating facilities is sold pursuant to long term contractual arrangements which have a weighted average remaining contract life of 14 years.

APCo owns or has interests in thermal energy facilities with approximately 350 MW of installed generating capacity. Approximately 93% of the electrical output from the owned thermal facilities is sold pursuant to long term Power purchase agreements ("PPA") with major utilities and which have a weighted average remaining contract life of 6 years.

APCo also has a pipeline of development projects that between 2014 and 2016 will add approximately 323 MW of generation capacity from wind powered generating stations and approximately 30 MW from photovoltaic solar powered generation stations with an average contract life of 22 years.

### Liberty Utilities Co.

Liberty Utilities is a diversified rate regulated utility providing electricity, natural gas, water distribution and wastewater collection utility services to approximately 480,000 connections. Liberty Utilities provides safe, high quality and reliable services to its ratepayers through its nationwide portfolio of utility systems and delivers stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities delivers continued growth in earnings through accretive acquisition of additional utility systems.

The utility systems owned by Liberty Utilities operate under rate regulation, generally overseen by the public utility commissions of the states in which they operate. Liberty Utilities reports the performance of its utility operations through three regions – West, Central, and East.

The Liberty Utilities (West) region is comprised of regulated electrical and water distribution and wastewater collection utility systems. The regulated electrical distribution utility and related generation assets (the "CalPeco Electric System") serve approximately 47,800 electric connections in the State of California. Liberty Utilities (West) region's regulated water and wastewater utility systems serve approximately 68,000 water and wastewater connections located in the State of Arizona.

The Liberty Utilities (Central) region is comprised of regulated natural gas and water distribution and wastewater collection utility systems. The regulated natural gas utilities serve approximately 85,600 natural gas connections located in the States of Missouri, Illinois, and Iowa. Liberty Utilities (Central) region's regulated water distribution and wastewater collection utilities serve approximately 29,400 water and wastewater customers located in the States of Arkansas, Illinois, Missouri, and Texas.

Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems located in the State of New Hampshire, and regulated natural gas distribution utility systems located in the States of Georgia and Massachusetts. Liberty Utilities provides regulated local electrical utility services to approximately 43,800 electric connections in the state of New Hampshire; and regulated local gas distribution utility services to approximately 206,200 natural gas connections located in the states of Georgia, New Hampshire and Massachusetts.

# Major Highlights

## 2013 Corporate Highlights

***Dividend Increased to $0.34 per Common Share Annually***

APUC has completed several acquisitions and has advanced a number of other initiatives that have raised the growth profile for APUC's earnings and cash flows which in turn supports an increase in the dividend to shareholders. As a result, on May 9, 2013, the Board approved a dividend increase of $0.03 per share annually bringing the total annual dividend to $0.34, paid quarterly at the rate of $0.085 per common share.

Management believes that the increase in the dividend is consistent with APUC's stated strategy of delivering total shareholder return comprised of attractive current dividend yield and capital appreciation founded on increased earnings and cash flows.

***Credit Rating Upgrade***

In the fourth quarter of 2013, Standard & Poor's Ratings Services raised its long-term corporate credit rating on APUC, APCo and Liberty Utilities to 'BBB' from 'BBB-'. As well, Standard & Poor's raised its global scale and Canada scale preferred stock ratings on APUC to 'BB+' and 'P-3 (High)' from 'BB' and 'P-3', respectively.

According to Standard & Poor's, the upgrade reflects a significant increase in regulated cash flow from Liberty Utilities owing to a number of acquisitions in the past 18 months, as well as an expectation that adjusted funds from operations-to-debt levels will continue to increase in the near-to-medium term. Standard & Poor's has also provided a stable outlook for the company owing to the assessment of relatively stable cash flows, supported by regulated cash flow from Liberty's regulated utility business, and APCo's largely contracted power asset portfolio.

The Company expects the rating to further improve access to the debt capital markets, reduce credit charges and a lower the overall cost of capital of the Company.

***Related party transactions***

In 2011, the Board formed an independent committee ("Independent Board Committee") and initiated a process to review all of the remaining historic business associations with APUC's Chief Executive Officer ("CEO") and Vice-Chair with an objective to reduce and/or eliminate these relationships.

The process initiated in 2011 has now been completed and all related party transactions between APUC and the CEO and Vice Chair have been resolved to the satisfaction of the Independent Board Committee and the Board. The resolution of the related party matters is described in more detail later in this MD&A under "Related Party Transactions".

***Strengthened Balance Sheet***

*Issuance of $100 million Preferred Shares*

Subsequent to year-end, on March 5, 2014, APUC issued 4.0 million cumulative rate resent preferred shares, Series D (the "Series D Shares") at a price of $25 per share, for aggregate gross proceeds of $100 million. The Series D Shares will yield 5.0% annually for the initial five-year period ending March 31, 2019. The preferred shares have been assigned a rating of P-3 (High) and Pfd-3 (Low) by S&P and DBRS respectively. The net proceeds of the offering will be used to partially finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's credit facilities and for general corporate purposes.

*Emera Share Subscription*

Pursuant to previously committed subscription receipts, on February 7, 2013, APUC issued 2.6 million shares at a price of $5.74 per share to Emera Incorporated ("Emera"). Additionally, on February 14, 2013, APUC issued 5.2 million shares at a price of $5.74 per share and 3.4 million shares at a price of $4.72 per share to Emera. On March 26th APUC issued 4.0 million common shares at a price of $7.40 per share for total cash proceeds of $29.3 million pursuant to a subscription agreement with Emera.

APUC believes issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

As a result, as at December 31, 2013, Emera owns 50.1 million APUC common shares representing approximately 24.2% of the total outstanding common shares of the Company.

*Conversion and Redemption of Series 3 Convertible Debentures to Equity*

On January 2, 2013, APUC completed a redemption of the outstanding Series 3 Debentures by issuing and delivering 150,816 APUC common shares for the remaining $1.0 million Series 3 Debentures.

### APUC Credit Facility

On November 19th, 2013, APUC amended its existing $30.0 million senior unsecured credit facility ("APUC Facility") to increase the commitments available to $65.0 million and extend maturity to November 19, 2016.

## 2013 Liberty Utilities Highlights

### Acquisition of the New England Gas System

On February 11, 2013, Liberty Utilities entered into an agreement with The Laclede Group, Inc. (“Laclede”) to assume Laclede’s rights to purchase the assets of the New England Gas Company (“New England Gas System”) from an affiliate of Southern Union Company. The New England Gas System is a natural gas distribution utility serving over 55,000 connections in Massachusetts. The acquisition closed in the fourth quarter of 2013. The results of the New England Gas System are reported in the Liberty Utilities (East) region.

Total purchase price for the New England Gas System is approximately U.S. $59.1 million, subject to certain working capital and other closing adjustments. The acquisition was funded using a targeted 52% equity, 48% debt capital structure including the assumption of U.S. $19.5 million of existing debt.

### Acquisition of the Peach State Gas System

On April 1, 2013 Liberty Utilities completed the acquisition of regulated natural gas distribution utility systems serving Columbus and Gainesville, Georgia (“Peach State Gas System”, formerly known as Columbus/Gainseville Gas System). The total purchase price for the Peach State Gas System adjusted for certain working capital and other closing adjustments, is approximately U.S. $153.0 million. The regulated natural gas distribution utilities provide natural gas service to approximately 60,000 total connections in Georgia.

### Acquisition of the Pine Bluff Water System

On February 1, 2013, Liberty Utilities completed the acquisition of issued and outstanding shares of United Water Arkansas Inc. (“Pine Bluff Water System”), a regulated water distribution utility from United Waterworks Inc. The Pine Bluff Water System is located in Pine Bluff, Arkansas and serves approximately 17,700 water distribution connections. Total purchase price for the Pine Bluff Water System, adjusted for certain working capital and other closing adjustments, is approximately U.S. $27.9 million.

### Acquisition of Remaining Interest in the CalPeco Electric System

On February 14, 2013, APUC issued 3.4 million common shares to Emera representing the balance of the subscription receipts outstanding pursuant to the acquisition in 2012 of the remaining 49.999% ownership in California Pacific Utility Ventures LLC, which owns 100% of the CalPeco Electric System.

### U.S. Debt Private Placements

On July 31, 2013, Liberty Utilities issued U.S. $125.0 million of debt through a private placement in the U.S. The financing is the third series of notes issued pursuant to Liberty Utilities’ master indenture. The notes are senior unsecured with an average life maturity of approximately ten years and a weighted average coupon of 3.81%. The proceeds of the private placement financing were used to repay a U.S. $100.0 million short term acquisition facility used in connection with the acquisition of the Peach State Gas System, reduce the drawn amount on Liberty’s revolving credit facility and for general corporate purposes.

On March 14, 2013 Liberty Utilities completed a U.S. $15.0 million private placement debt financing. The notes are senior unsecured with a 10 year term and a coupon of 4.14%.

### Liberty Utilities Credit Facility

On September 30, 2013, Liberty Utilities increased the credit available under the senior unsecured revolving credit facility (the "Liberty Facility") to U.S. $200.0 million from U.S. $100.0 million. The larger credit facility provides Liberty Utilities with the additional liquidity required resulting from the various acquisitions completed in 2013 and on execution of near term organic growth opportunities. In addition to a larger credit facility, the tenor has been increased from three years to five years and several other terms under the facility, including pricing, have improved. The amended facility will now expire on September 30, 2018.

### *Granite State Electric System Rate Proceedings*

On March 29, 2013, the Granite State Electric System with the NHPUC seeking an increase in rates of U.S. $13.0 million, and an additional U.S. $1.2 million increase in 2014 subject to the completion of certain capital projects. The filing is based on a 2012 test year, with revenues and expenses adjusted to reflect known and measurable changes. Among other things, Granite State Electric System requested and received approval to continue the current cost-recovery tracking mechanism related to the Reliability Enhancement and Vegetation Management Plan and was granted an annual rate increase of U.S. $0.4 million starting July 1, 2013. The Granite State Electric System also requested a modification to allow for recovery of pre-staging personnel and equipment for qualifying storms. On June 27, 2013, the NHPUC approved a settlement agreement authorizing a temporary annual rate increase of U.S. $6.5 million effective July 1, 2013, and provides recognition for Liberty to request an increase to its storm recovery adjustment factor ("SRAF"). On January 22, 2014, the Granite State Electric System entered a settlement with the New Hampshire PUC Staff, which will provide for a rate increase of U.S. $10.9 million consisting of U.S. $9.8 million in base rates and an additional U.S. $1.1 million for incremental capital expended after the test year. In addition, the settlement allows for one time recovery of rate case expenses of U.S. $0.4 million. It is anticipated that the settlement will be approved in late in Q1 2014.

## 2013 Algonquin Power Co. Highlights

### *Agreement to Acquire the Remaining 40% of a 400 MW Wind Power Portfolio*

On November 28, 2013, APCo entered into an agreement to acquire the remaining 40% of the 400 MW wind power portfolio (the "U.S. Wind Portfolio") in the United States from Gamesa Wind US, LLC ("Gamesa") for total consideration of approximately U.S. $117.0 million.

APCo currently holds a 60% controlling interest in the U.S. Wind Portfolio which were originally acquired through a newly formed partnership whose original members included APCo, Gamesa and certain tax equity investors. The 400 MW wind portfolio consists of three facilities, Minonk (200MW), Senate (150MW), and Sandy Ridge (50MW) located in the states of Illinois, Texas, and Pennsylvania, respectively.

APCo has been the majority owner and manager of the U.S. Wind Portfolio since 2012 when commercial operation was achieved, therefore no additional ongoing management or administrative costs are expected to be incurred. Gamesa will continue to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities under 20 year contracts. The acquisition will be funded primarily from the proceeds from the APCo $200.0 million debentures issued early in 2014.

### *Acquisition of the 20 MWac Bakersfield Solar Project*

On November 28, 2013, APCo entered into an agreement to purchase and complete construction of a 20 MWac Bakersfield Solar Facility ("Bakersfield Solar Project") located in Kern County, California. Following commissioning, the Bakersfield solar project is expected to generate 53.3 GW-hrs of energy per year. All energy from the project will be sold to PG&E pursuant to a 20 year agreement with expected first full year revenues of U.S. $4.7 million. APCo plans to enter into a partnership agreement with a third party (the "Tax Partner") pursuant to which the Tax Partner will receive the majority of the tax attributes associated with the project. It is anticipated that the total expected capital costs for the project of U.S. $58.5 million will be funded as to 55% by APCo and the balance by the Tax Partner. Subject to receipt of final permits and approvals and reaching satisfactory agreement with the Tax Partner, construction of the project is anticipated to commence in the second quarter of 2014 with a commercial operations date expected to occur in late 2014.

### *Acquisition of Shady Oaks Wind Facility*

On January 1, 2013, APCo acquired a 109.5 MW contracted wind powered generating station ("Shady Oaks Wind Facility") by assuming long-term debt of U.S. $150.0 million and for no additional cash, subject to final closing adjustments for working capital, energy generated by the projected and basis differences between node and hub prices.

The Shady Oaks Wind Facility is located in Northern Illinois, approximately 80 km west of Chicago, Illinois and achieved commercial operation in June 2012.

The facility is comprised of 68 Goldwind GW82 1.5MW and 3 Goldwind GW100 2.5MW permanent magnet direct-drive wind turbines; these turbines are well suited for the wind regime, and offer significant technological advantages providing proven reliability, enhanced energy production efficiency and lower long term maintenance costs. Through its affiliate, Goldwind International SO Limited has assumed all operations, maintenance, and capital repair responsibilities for the Shady Oaks Wind Facility pursuant to a 20 year fixed price agreement for the turbines and balance of plant facilities.

Total annual energy production is expected to be 364 GW-hrs per year. The Shady Oaks Wind Facility has entered into a 20 year inflation indexed power purchase agreement with the largest electric utility in the state of Illinois, Commonwealth Edison (BBB flat stable: Moody's, S&P) for 310 GW-hrs of energy per year. All energy produced in excess of that sold under the power purchase agreement will be sold into the energy market in which the facility is located.

### *Energy From Waste Facility*

During the second quarter of 2013, the Company concluded that its Energy from Waste ("EFW") and Brampton Cogeneration Inc. ("BCI") Thermal Facilities were no longer considered strategic to its ongoing operations, commenced a process to divest of the facilities and wrote the net assets of the facilities down to its estimated fair value, less cost of sale which resulted in a write down of $35.7 million, net of tax. On February 7, 2014 the Company entered into an agreement to sell the EFW and BCI Thermal Facilities. Accordingly, the determination of the fair values of the net assets of EFW and BCI Themal Facilities were revised to reflect the estimated selling price under the agreement, which resulted in a further write down of the net assets of $6.8 million net of tax as at December 31, 2013. The final selling price is subject to customary closing adjustments. Closing of the transaction is subject to certain regulatory approvals which are expected to be received by the end of the first quarter or early in the second quarter of 2014.

### *Completion of Cornwall Solar Project*

During the second quarter APCo began construction of the 10 MWac solar projected located near Cornwall, Ontario. The facility is the first solar project in APCo's portfolio and is expected to add 13,900 MW-hrs of production annually. Completion of construction is expected late in the first quarter of 2014 at an estimated total capital cost of $45.0 million.

### *Sale of Small U.S. Hydro Facilities*

On March 14, 2013, APCo entered into an agreement to sell ten small U.S. hydroelectric generating facilities that were no longer considered strategic to the ongoing operations of the Company for gross proceeds of U.S. $27.0 million. APCo closed the sale of nine of the ten facilities on June 28, 2013 for total proceeds of approximately U.S. $23.4 million with the tenth facility expected to be sold in the second quarter of 2014. The operating results from these facilities for current and prior periods are therefore disclosed as discontinued operations on the consolidated statements of operations.

### *APCo $200 million Senior Unsecured Debentures*

On January 17, 2014, APCo issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "APCo Debentures") pursuant to a private placement in Canada and the United States. The APCo Debentures were sold at a price of $99.864 per $100.00 principal amount resulting in an effective yield of 4.67%. Concurrent with the offering, APCo entered into a fixed for fixed cross currency swap, coterminous with the APCo Debentures, to economically convert the Canadian dollar denominated debentures into U.S. dollars, resulting in an effective interest rate throughout the term of approximately 4.77%.

Net proceeds will be used towards financing the acquisition of the remaining 40% ownership interest in its U.S. Wind Portfolio, to reduce amounts outstanding on project debt related to its Shady Oaks Wind Facility, to reduce amounts outstanding under its bank credit facility and for general corporate purposes.

# 2013 Annual Results from Operations

APUC recorded significant growth in both its regulated and non-regulated utility businesses in 2013. The results for the year reflect the full year of operation from four newly acquired U.S. wind generation facilities and the full year of operation of U.S. gas and electric utilities acquired in 2012 and the additional acquisition of U.S. gas distribution and water distribution utilities in 2013.

## Key Selected Annual Financial Information

| (millions of dollars except per share information) | Year ended December 31 2013 | 2012 | 2011 |
|---|---|---|---|
| Revenue | **$ 675.3** | $ 348.8 | $ 247.5 |
| Adjusted EBITDA [1] | **226.9** | 88.1 | 94.4 |
| Cash provided by operating activities | **98.9** | 63.0 | 69.7 |
| Adjusted funds from operations[1] | **153.5** | 66.8 | 63.6 |
| Net earnings attributable to Shareholders from continuing operations | **62.3** | 13.5 | 22.9 |
| Net earnings attributable to Shareholders | **20.3** | 14.5 | 23.4 |
| Adjusted net earnings [1] | **60.9** | 18.9 | 37.0 |
| Dividends declared to Common Shareholders | **68.3** | 50.2 | 32.4 |
| Weighted Average number of common shares outstanding | **204,350,689** | 158,304,340 | 116,712,934 |
| Per share | | | |
| Basic net earnings from continuing operations | **$ 0.28** | $ 0.08 | $ 0.20 |
| Basic net earnings | **$ 0.07** | $ 0.09 | $ 0.20 |
| Adjusted net earnings [1, 2] | **$ 0.27** | $ 0.11 | $ 0.32 |
| Diluted net earnings | **$ 0.07** | $ 0.09 | $ 0.20 |
| Cash provided by operating activities [1, 2] | **$ 0.48** | $ 0.40 | $ 0.60 |
| Adjusted funds from operations[1, 2] | **$ 0.72** | $ 0.42 | $ 0.54 |
| Dividends declared to Common Shareholders | **$ 0.33** | $ 0.30 | $ 0.27 |
| Total assets | **3,472.6** | 2,779.0 | 1,282.3 |
| Long term liabilities [3] | **1,255.6** | 770.8 | 455.0 |

1 APUC uses adjusted EBITDA, adjusted net earnings and adjusted funds from operations to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions. (see "Non-GAAP Financial Measures")

2 APUC uses per share adjusted net earnings, cash provided by operating activities and adjusted funds from operations to enhance assessment and understanding of the performance of APUC.

3 Long term debt includes current and long term portion of debt and convertible debentures.

For the year ended December 31, 2013, APUC experienced an average U.S. exchange rate of approximately $1.0301 as compared to $0.999 in the same period in 2012. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's Canadian dollar reporting currency.

For the year ended December 31, 2013, APUC reported total revenue of $675.3 million as compared to $348.8 million during the same period in 2012, an increase of $326.5 million or 93.6%. The major factors resulting in the increase in APUC revenue for the year ended December 31, 2013 as compared to the corresponding period in 2012 are set out as follows:

| | | Year to date December 31, 2013 (millions) |
|---|---|---|
| Comparative Prior Period Revenue | $ | 348.8 |
| Significant Changes: | | |
| Liberty Utilities: | | |
| West – Implementation of decoupling mechanism and increased customer demand | | 4.1 |
| Central – Revenue increase due to the Midstates Gas Systems, and the Pine Bluff Water System acquisitions | | 59.0 |
| East – Increased revenue resulting from the acquisitions of: the EnergyNorth Gas System, the Granite State Electric System, the Peach State Gas System, and the New England Gas System | | 176.1 |
| APCo: | | |
| Renewable: | | |
| Acquisition of the Sandy Ridge, Minonk, Senate and Shady Oaks Wind Facilities (collectively, the "U.S. Wind Facilities") | | 50.5 |
| Sale of Renewable Energy Credits generated from the U.S. Wind Facilities | | 5.7 |
| Increased demand for retail sales at AES | | 2.1 |
| St Leon II Wind Facility – Revenue increase from expansion | | 1.9 |
| Effect of hydrology resource compared to comparable period in prior year | | 4.5 |
| Thermal: | | |
| Sanger Facility - Increase due to planned shutdown in 2012 | | 4.6 |
| Impact of the stronger U.S. dollar | | 18.8 |
| Other | | (0.8) |
| Current Period Revenue | $ | 675.3 |

A more detailed discussion of these factors is presented within the business unit analysis.

Adjusted EBITDA in the year ended December 31, 2013 totalled $226.9 million as compared to $88.1 million during the same period in 2012, an increase of $138.8 million or 157.5%. The increase in Adjusted EBITDA was primarily due to acquisitions completed in 2012 and 2013, impact of rate case settlements, increased hydrology and increased customer demand at the CalPeco Electric System. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the year ended December 31, 2013, net earnings from continuing operations attributable to Shareholders totalled $62.3 million as compared to $13.5 million during the same period in 2012, an increase of $48.8 million. The increase was due to $112.3 million in increased earnings from operating facilities, $0.5 million in increased interest, dividend and other income, $5.5 million in decreased acquisition costs, $5.0 million in increased gains from derivative instruments, and $18.2 million in decreased allocations of earnings to non-controlling interests as compared to the same period in 2012. These items were partially offset by $46.8 million increased depreciation and amortization expense, $3.9 million in increased administration charges, $17.7 million in higher interest expense, $0.8 million in increased losses on sale of assets, and $23.5 million in increased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses).*

For the year ended December 31, 2013, net earnings (including discontinued operations) attributable to Shareholders totalled $20.3 million as compared to $14.5 million during the same period in 2012, an increase of $5.8 million. Net earnings per share totalled $0.07 for the year ended December 31, 2013, as compared to $0.09 during the same period in 2012.

During the year ended December 31, 2013, cash provided by operating activities totalled $98.9 million or $0.48 per share as compared to cash provided by operating activities of $63.0 million, or $0.40 per share during the same period in 2012. During the year ended December 31, 2013, adjusted funds from operations, a non-GAAP measure, totalled $153.5 million or $0.72 per share as compared to adjusted funds from operations of $66.8 million, or $0.42 per share during the same period in 2012 an increase of 86.7 million.

Cash per share provided by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided by operating activities and per share adjusted funds from operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided by operating activities and per share adjusted funds from operations do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

## 2013 Three month results from operations

### Key Selected Fourth Quarter Financial Information

| | Quarter ended December 31 | |
|---|---|---|
| **(millions of dollars except per share information)** | **2013** | **2012** |
| Revenue | **$ 205.3** | $ 138.9 |
| Adjusted EBITDA [1] | **67.6** | 24.0 |
| Cash provided by operating activities | **31.3** | 17.1 |
| Adjusted funds from operations[1] | **45.9** | 24.6 |
| Net earnings attributable to Shareholders from continuing operations | **19.8** | 6.8 |
| Net earnings attributable to Shareholders | **13.1** | 6.4 |
| Adjusted net earnings[1] | **18.5** | 6.5 |
| Dividends declared to Common Shareholders | **17.6** | 15.5 |
| Weighted Average number of common shares outstanding | **206,219,121** | 169,860,332 |
| Per share | | |
| Basic net earnings/(loss) from continuing operations | **$ 0.09** | $ 0.04 |
| Basic net earnings/(loss) | **$ 0.06** | 0.03 |
| Adjusted net earnings[1, 2,] | **$ 0.08** | $ 0.03 |
| Diluted net earnings/(loss) | **$ 0.06** | $ 0.05 |
| Cash provided by operating activities [1, 2,] | **$ 0.15** | $ 0.10 |
| Adjusted funds from operations[1, 2] | **$ 0.22** | $ 0.14 |
| Dividends declared to Common Shareholders | **$ 0.09** | $ 0.08 |

1 APUC uses adjusted EBITDA, adjusted net earnings and adjusted funds from operations to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions. (see "Non-GAAP Financial Measures")

2 APUC uses per share adjusted net earnings, cash provided by operating activities and adjusted funds from operations to enhance assessment and understanding of the performance of APUC.

For the three months ended December 31, 2013, APUC experienced an average U.S. exchange rate of approximately $1.050 as compared to $0.991 in the same period in 2012. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

For the three months ended December 31, 2013, APUC reported total revenue of $205.3 million as compared to $138.9 million during the same period in 2012, an increase of $66.4 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2013 as compared to the corresponding period in 2012 are set out as follows:

| | | Quarter ended December 31, 2013 (millions) |
|---|---|---|
| Comparative Prior Period Revenue | $ | 138.9 |
| Significant Changes: | | |
| Liberty Utilities: | | |
| West – Implementation of decoupling mechanism and increased customer demand | | 0.3 |
| Central – Revenue increase due to the acquisition of the Pine Bluff Water System and increased customer demand in the Midstates Gas Systems. | | 5.0 |
| East – Revenue increase due to the acquisition of the Peach State Gas System and the New England Gas System and increased customer demand at the Granite State Electric System and the EnergyNorth Gas System | | 32.4 |
| APCo: | | |
| Renewable | | |
| Acquisition of the Minonk, Senate and Shady Oaks Wind Facilities | | 12.1 |
| Sale of Renewable Energy Credits generated from the U.S. Wind Facilities | | 2.2 |
| Effect of hydrology resource compared to comparable period in prior year | | 1.1 |
| Increased rates at AES | | 1.7 |
| St. Leon Wind Facilities - Increased average realized rates | | 0.9 |
| Thermal | | |
| Increased average price at the Sanger Facility | | 0.5 |
| Impact of the stronger U.S. dollar | | 12.0 |
| Other | | (1.8) |
| Current Period Revenue | $ | 205.3 |

A more detailed discussion of these factors is presented within the business unit analysis.

Adjusted EBITDA in the three months ended December 31, 2013 totalled $67.6 million as compared to $24.0 million during the same period in 2012, an increase of $43.6 million or 181.7%. The increase in Adjusted EBITDA was primarily due to acquisitions completed in 2012 and 2013, impact of rate case settlements, increased hydrology and increased customer demand at the CalPeco Electric System. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended December 31, 2013, net earnings attributable to Shareholders from continued operations totalled $19.8 million as compared to $6.8 million during the same period in 2012, an increase of $13.0 million. The increase was due to $28.3 million increased earnings from operating facilities, $0.2 million in decreased administration charges, $0.6 million in decreased acquisition costs, $2.3 million in increased gains from derivative instruments, and $9.7 million decrease in allocations of earnings to non-controlling interests as compared to the same period in 2012. These items were partially offset by $10.5 million increased depreciation and amortization expense, $1.4 million due to a decrease in foreign exchange gain, $3.2 million in higher interest expense, $0.7 million decrease in interest, dividend and other income, $0.6 increased losses on sale of assets, and $11.7 million in increased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)* as compared to the same period in 2012.

For the three months ended December 31, 2013, net earnings (including discontinued operations) attributable to Shareholders totalled $13.1 million as compared to net earnings attributable to Shareholders of $6.4 million during the same period in 2012, an increase of $6.7 million. Net earnings per share totalled $0.06 for the three months ended December 31, 2013, as compared to net earnings per share of $0.03 during the same period in 2012.

During the three months ended December 31, 2013, cash provided by operating activities totalled $31.3 million or $0.15 per share as compared to cash provided by operating activities of $17.1 million, or $0.10 per share during the same period in 2012. During the three months ended December 31, 2013, adjusted funds from operations totalled $45.9 million or $0.22 per share as compared to adjusted funds from operations of $24.6 million, or $0.14 per share during the same period in 2012. The change in adjusted funds from operations in the three months ended December 31, 2013, is primarily due to increased earnings from operations, as compared to the same period in 2012.

Cash per share provided by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided by operating activities and per share adjusted funds from operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided by operating activities and per share adjusted funds from operations do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

# APCo: Renewable Energy Division

| | | Three months ended December 31 | | | Year ended December 31 | |
|---|---|---|---|---|---|---|
| | Long Term Average Resource | 2013 | 2012 | Long Term Average Resource | 2013 | 2012 |
| **Performance (GW-hrs sold)** | | | | | | |
| Hydro Facilities: | | | | | | |
| Ontario Region[7] | **33.8** | **39.3** | 7.3 | **141.0** | **90.4** | 95.4 |
| Quebec Region | **73.1** | **68.0** | 70.0 | **275.9** | **277.6** | 263.4 |
| Maritime Region (incl TPI) | **45.6** | **37.9** | 31.6 | **177.7** | **203.1** | 133.1 |
| Western Region | **12.6** | **12.1** | 11.5 | **65.0** | **66.6** | 64.8 |
| | **165.1** | **157.3** | 120.4 | **659.6** | **637.7** | 556.7 |
| Wind Facilities: | | | | | | |
| Manitoba Region | **121.4** | **116.5** | 106.6 | **430.2** | **398.0** | 405.0 |
| Saskatchewan Region[1] | **24.1** | **22.8** | 20.7 | **88.0** | **79.1** | 82.7 |
| Pennsylvania Region[2] | **43.6** | **38.7** | 34.8 | **158.3** | **138.8** | 55.9 |
| Illinois Region[3] | **296.2** | **271.5** | 46.8 | **1,037.4** | **938.8** | 46.8 |
| Texas Region[4] | **140.0** | **133.8** | 33.9 | **520.4** | **524.5** | 33.9 |
| | **625.3** | **583.3** | 242.8 | **2,234.3** | **2,079.2** | 624.3 |
| **Total** | **790.4** | **740.6** | 363.2 | **2,893.9** | **2,716.9** | 1,181.0 |

| | | | | |
|---|---|---|---|---|
| **Revenue[5]** | (millions) | (millions) | (millions) | (millions) |
| Energy sales | **$ 40.3** | $ 22.9 | **$ 145.6** | $ 84.2 |
| Less: | | | | |
| Cost of Sales – Energy[6] | **(3.8)** | (1.7) | **(8.8)** | (8.9) |
| Net Energy Sales | **$ 36.5** | $ 21.2 | **$ 136.8** | $ 75.3 |
| Renewable Energy Credits | **2.3** | 0.2 | **5.7** | 0.2 |
| Other Revenue | **0.3** | 0.6 | **1.4** | 1.7 |
| Total Net Revenue | **$ 39.1** | $ 22.0 | **$ 143.9** | $ 77.2 |
| **Expenses** | | | | |
| Operating expenses | **(11.3)** | (5.3) | **(40.1)** | (21.4) |
| Interest and Other income | **0.5** | 0.5 | **1.9** | 2.0 |
| HLBV income/(loss) | **6.8** | (9.5) | **20.4** | (10.7) |
| Division operating profit | **$ 35.1** | $ 7.7 | **$ 126.1** | $ 47.1 |

1 APUC does not consolidate the operating results from this facility in its financial statements. Production from the facility is included as APUC manages the facility under contract and has an option to acquire a 75% equity interest in the facility in 2016.

2 Represents the operations of the Sandy Ridge Wind Facility which was acquired on July 1, 2012.

3 Represents the operations of the Minonk and the Shady Oaks Wind Facilities which were acquired on December 10, 2012 and January 1, 2013, respectively. Production at the Shady Oaks was 88.7 GWhrs in the 3 month period and 317.1 GWhrs in the 12 month period ended December 31, 2013. Production at Shady Oaks can be subject to congestion related curtailment by the independent system operator but in this case compensation is expected to be received for lost energy sales.

4 Represents the operations of the Senate Wind Facility which was acquired on December 10, 2012.

5 While most of APCo's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division, as compared to the same period in the prior year.

6 Cost of Sales - Energy consists of energy purchases by Algonquin Energy Services ("AES") which is resold to its retail and industrial customers. Under GAAP, in APUC's year-end consolidated Financial Statements, these amounts are included in operating expenses.

7 APCo's Long Sault hydro facility was offline during most of the first nine months of 2013 but with lost revenue covered by insurance. See below for additional commentary

## 2013 Annual Operating Results

Production data, revenue and expenses have been adjusted to remove the results of the New York and New England Hydro Facilities which are now disclosed as discontinued operations. See Financial Statement note 20 for details.

For the twelve months ended December 31, 2013, the Renewable Energy Division produced 2,716.9 GW-hrs of electricity, as compared to 1,181.0 GW-hrs produced in the same period in 2012, an increase of 130.1%. The increased generation is primarily due to the acquisition of Sandy Ridge, Minonk, Senate, and Shady Oaks Wind Facilities. This level of production represents sufficient renewable energy to supply the equivalent of 201,200 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 1,992,400 tons of $CO_2$ gas was prevented from entering the atmosphere in the twelve months ended 2013.

Adjusting for the effect of the unplanned outage at APCo's Long Sault Hydro Facility generating station, during the twelve months ended December 31, 2013, the division generated electricity equal to 95.3% of long-term projected average resources (wind and hydrology) as compared to 92.8% during the same period in 2012. As a result, the division's operating profit for the twelve months ended December 31, 2013 is $11.0 million lower than what would have been generated had the facilities achieved their expected long term average production. In the twelve months of 2013, the Maritime region's operating facilities produced 14% above long-term average resources; while the Quebec, Western, and Texas regions produced 1% to 5% higher than long-term average resources. The Ontario, Manitoba, Saskatchewan, Pennsylvania, and Illinois regions experienced resources lower than long-term average resources, producing 10% to 15% below long-term average resources.

For the twelve months ended December 31, 2013, revenue from energy sales in the Renewable Energy Division totalled $145.6 million, as compared to $84.2 million during the same period in 2012, an increase of $61.4 million. As the purchase of energy by the Algonquin Energy Services ("AES) Business is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's sales results. For the twelve months ended December 31, 2013, net energy sales in the Renewable Energy Division totalled $136.8 million, as compared to $75.3 million during the same period in 2012.

Revenue from generation at APCo's hydro facilities located in the Ontario (excluding Long Sault), Quebec and Western regions increased by $3.1 million primarily as a result of better hydrology in the Quebec Region and Dickson Dam. Lost production from the unplanned shutdown at the Long Sault generating facility in Ontario was largely covered by business interruption insurance claim proceeds and hence did not have a significant impact on 2013 results. Revenue from APCo's hydro facility located in the Maritime region increased by $0.4 million primarily due to a $2.0 million increase in production due to better hydrology, offset by a $1.6 million decrease in weighted average energy rates, as compared to the same period in 2012.

Revenue from APCo's wind facilities located in the Manitoba region increased $1.6 million due primarily to $1.9 million from the expansion of St. Leon Wind Facility, offset partially by $0.3 million due to lower wind resources. Revenues from APCo's Sandy Ridge Wind Facility located in the Pennsylvania region increased $3.7 million as compared to the same period in 2012 as the facility was acquired on July 1, 2012. Revenues from APCo's wind facilities located in the Texas and Illinois regions increased by $48.4 million given that these facilities were acquired in December 2012 and January 2013.

Revenue at AES increased $2.3 million or 11% primarily due to increased customer load served. Revenue at AES primarily consists of wholesale deliveries to local electric utilities, retail sales to commercial and industrial customers in Northern Maine, merchant sales of production in excess of committed customer deliveries from the Tinker Facility and other revenue.

For the twelve months ended December 31, 2013, energy purchase costs by AES totalled $8.8 million as compared to $8.9 million during the same period in 2012, a decrease of $0.1 million. AES' energy purchase costs for the twelve months ended December 31, 2013 was primarily due to a lower volume of energy purchases from external suppliers due to increased power supplied from the Tinker facility, partially offset by higher average prices. During this period, AES purchased approximately 91.6 GW-hrs of energy at market and fixed rates averaging U.S. $93.4 per MW-hr. During the twelve months, the Maritime region generated approximately 67% of the energy required to service its customers as well as AES' customers, as compared to 44% in the same period in 2012.

For the twelve months ended December 31, 2013, Renewable Energy Credits ("REC") revenue totalled $5.7 million as compared to $0.2 million in the same period in 2012, representing an increase of $5.5 million. REC units are generated at a ratio of one REC unit per one MWHr generated and are sold in the market in which the REC is generated. For the twelve months ended December 31, 2013, REC units and related revenue units were generated at the Sandy Ridge, Minonk, Senate and Shady Oaks Wind Facilities.

The Red Lily I Wind Facility located in Saskatchewan produced 79.1 GW-hrs of electricity for the twelve months ended December 31, 2013. APCo's economic return from its investment in Red Lily I Wind Facility currently comes in the form of interest payments, fees and other charges and is not reflected in revenue from energy sales. Under the terms of the agreements, APCo has the right to exchange these contractual and debt interests in Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the twelve months ended December 31, 2013, APCo earned fees of $1.2 million (which is classified as other revenue) and interest income of $1.6 million from Red Lily I.

For the twelve months ended December 31, 2013, operating expenses excluding energy purchases totalled $40.1 million, as compared to $21.4 million during the same period in 2012, an increase of $18.7 million. The higher expenses were primarily due to the newly acquired Sandy Ridge, Senate, Minonk, and Shady Oaks Wind Facilities partially offset by lower lease and water usage costs at the Long Sault and Cote St. Catherine Hydro Facilities.

For the twelve months ended December 31, 2013 , interest and other income totalled $1.9 million, as compared to $2.0 million in the same period in 2012. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I Wind Facility. This amount is included as part of APCo's earnings from its investment in Red Lily I Wind Facility, as discussed above.

Hypothetical Liquidation at Book Value ("HLBV") income represents the value of the net tax attributes generated by APCo in the period from certain of its U.S. wind power generation facilities. The value of net tax attributes generated in the twelve months ended December 31, 2013 amounted to an approximate HLBV income of $20.4 million as compared to an HLBV loss of $10.7 million during the same period in 2012. The prior year HLBV loss was primarily a result of the accelerated depreciation election that was available in the first year of operations.

For the twelve months ended December 31, 2013, the Renewable Energy Division's operating profit totalled $126.1 million , as compared to $47.1 million during the same period in 2012, representing an increase of $79.0 million. As a result of the stronger U.S. dollar, operating profit increased by $1.4 million.

## 2013 Fourth Quarter Operating Results

For the quarter ended December 31, 2013, the Renewable Energy Division produced 740.6 GW-hrs of electricity, as compared to 363.2 GW-hrs produced in the same period in 2012, an increase of 103.9%. The increased generation is primarily due to the acquisition of the Minonk, Senate and Shady Oaks Wind Facilities. This level of production represents sufficient renewable energy to supply the equivalent of 164,400 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 407,330 tons of $CO_2$ gas was prevented from entering the atmosphere in the fourth quarter 2013.

Adjusting for the effect of the unplanned outage at APCo's Long Sault generating station during the quarter ended December 31, 2013, the division generated electricity equal to 92.6% of long-term projected average resources (wind and hydrology) as compared to 89.5% during the same period in 2012. As a result, the division's operating profit for the quarter ended December 31, 2013 is $6.3 million lower than what would have been generated had the facilities achieved their expected long term average production. In the fourth quarter of 2013, the Texas and Ontario regions operating facility produced 4% above long-term average resources; while Quebec and Western regions produced 4% to 7% lower than long-term average resources. The Maritime, Saskatchewan, Manitoba, Pennsylvania and Illinois regions were 12% to 19% below long-term average resources.

For the quarter ended December 31, 2013, revenue from energy sales in the Renewable Energy Division totalled $40.3 million , as compared to $22.9 million during the same period in 2012, for an increase of $17.4 million. As the purchase of energy by AES is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's sales results. For the quarter ended December 31, 2013, net energy sales in the Renewable Energy Division totalled $36.5 million, as compared $21.2 million during the same period in 2012.

Revenue from generation at APCo's hydro facilities located in the Ontario (excluding Long Sault), Quebec and Western regions totalled $6.7 million which was consistent with the same period in 2012. The Long Sault generating facility in Ontario, returned to full operation in the third quarter resulting in an increase of $3.0 million from generation as compared to $1.8 million received from business interruption insurance in the same period in 2012. Revenue from APCo's hydro facility located in the Maritime region increased $0.2 million primarily due to increase in weighted average energy rates.

Revenue from APCo's wind facilities located in the Manitoba region increased $0.8 million due to higher wind resources at St. Leon Wind Facility. Revenues from APCo's Sandy Ridge Wind Facility located in the Pennsylvania region increased $0.3 million as compared to the same period in 2012. Revenue from APCo's wind facilities located in the Texas and Illinois regions increased $12.5 million as the facilities were acquired in the fourth quarter of 2012 and first quarter of 2013.

For the three month ended December 31, 2013, revenue at AES increased $1.8 million or 46% primarily due to increased customer load served. Revenue at AES primarily consists of wholesale deliveries to local electric utilities, retail sales to commercial and industrial customers in Northern Maine, merchant sales of production in excess of committed customer deliveries from the Tinker Facility and other revenue.

For the quarter ended December 31, 2013, energy purchase costs by AES totalled $3.8 million as compared to $1.7 million during the same period in 2012, an increase of $2.1 million. AES' increased energy purchase costs for the quarter ended December 31, 2013 was primarily due to a higher volume of energy purchases from external suppliers, at higher average prices. During this period, AES purchased approximately 40.8 GW-hrs of energy at market and fixed rates averaging U.S. $88 per MW-hr. During the quarter, the Maritime region generated approximately 44% of the load required to service its customers as well as AES' customers, as compared to 52% in the same period in 2012.

For the quarter ended December 31, 2013, REC revenue totalled $2.3 million as compared to $0.2 million in the same period in 2012, representing an increase of $2.1 million. REC units are generated at a ratio of one REC unit per one MWHr generated and are sold in the market in which the REC is generated. For the quarter ended December 31, 2013, REC units and related revenues were generated at the Sandy Ridge, Minonk, Senate and Shady Oaks Wind Facilities.

The Red Lily I Wind Facility located in Saskatchewan produced 22.8 GW-hrs of electricity for the quarter ended December 31, 2013. APCo's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges and is not reflected in revenue from energy sales. Under the terms of the agreements, APCo has the right to exchange these contractual and debt interests in Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the quarter ended December 31, 2013, APCo earned fees of $0.2 million (which is classified as other revenue) and interest income of $0.4 million from Red Lily I Wind Facility.

For the quarter ended December 31, 2013, operating expenses excluding energy purchases totalled $11.3 million, as compared to $5.3 million during the same period in 2012, an increase of $6.0 million. The increase was primarily driven by the increase in costs as a result of the newly acquired Senate, Minonk, and Shady Oaks Wind Facilities.

For the quarter ended December 31, 2013, interest and other income totalled $0.5 million, consistent with the same period in 2012. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I Wind Facility. This amount is included as part of APCo's earnings from its investment in Red Lily I Wind Facility, as discussed above.

Hypothetical Liquidation at Book Value ("HLBV") income represents the value of net tax attributes generated by APCo in the period from certain of its U.S. wind power generation facilities. The value of net tax attributes generated in the quarter ended December 31, 2013, amounted to an approximate HLBV income of $6.8 million as compared to HLBV loss of $9.5 million. The prior year HLBV loss was primarily a result of the accelerated depreciation election that was available in the first year of operations.

For the quarter ended December 31, 2013, the Renewable Energy Division's operating profit totalled $35.1 million, as compared to $7.7 million during the same period in 2012, representing an increase of $27.4 million. As a result of the stronger U.S. dollar operating profit increased by $0.7 million.

# APCo: Thermal Energy Division

| | Twelve months ended December 31, 2013 | | | Twelve months ended December 31, 2012 | | |
|---|---|---|---|---|---|---|
| | Windsor Locks | Sanger | Total | Windsor Locks | Sanger | Total |
| **Performance**(GW-hrs sold) | **115.3** | **137.2** | **252.5** | 190.2 | 100.2 | 290.4 |
| **Performance**(steam sales – billion lbs) | **623.0** | **—** | **623.0** | 602.2 | — | 602.2 |
| (all amounts in millions) | | | | | | |
| Revenue | | | | | | |
| Energy/steam sales | **$ 17.7** | **$ 16.9** | **$ 34.6** | $ 17.7 | $ 12.4 | $ 30.1 |
| Less: | | | | | | |
| Cost of Sales – Fuel | **(11.2)** | **(6.0)** | **(17.2)** | (11.7) | (2.9) | (14.6) |
| Net Energy Sales | **$ 6.5** | **$ 10.9** | **$ 17.4** | $ 6.0 | $ 9.5 | $ 15.5 |
| Other revenue | **0.5** | **1.9** | **2.4** | 0.3 | 1.4 | 1.7 |
| Total net revenue | **$ 7.0** | **$ 12.8** | **$ 19.8** | $ 6.3 | $ 10.9 | $ 17.2 |
| **Expenses** | | | | | | |
| Operating expenses | **(3.7)** | **(4.9)** | **(8.6)** | (4.5) | (4.1) | (8.6) |
| Facility operating profit | **$ 3.3** | **$ 7.9** | **$ 11.2** | $ 1.8 | $ 6.8 | $ 8.6 |
| Interest and other income | | | **0.2** | | | 0.5 |
| Divisional operating profit | | | **$ 11.4** | | | $ 9.1 |

APCo's Sanger and Windsor Locks Thermal Facilities generation facilities purchase natural gas from different suppliers and at prices based on different regional hubs. As a result, the average landed cost per unit of natural gas will differ between facility and regional changes in the average landed cost for natural gas may result in one facility showing increasing costs per unit while the other shows decreasing costs, as compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each MMBTU.

## 2013 Annual Operating Results

Production data, revenue and expenses have been adjusted to remove the results of the EFW Facility which are now disclosed as discontinued operations. See Financial Statement note 20 for details.

For the twelve months ended December 31, 2013, the Thermal Energy Division produced 252.5 GW-hrs of energy as compared to 290.4 GW-hrs of energy in the comparable period of 2012. The decrease in energy production was due primarily to the installation of the new Titan turbine at Windsor Locks Thermal Facility which is a smaller, more efficient turbine, sized to optimize the energy and steam requirements of the steam host, and to minimize exposure of the facility to the ISO NE electricity market, compared to the larger Frame 6 turbine that was operating in previous years. This is partially offset by an increased production at Sanger as a result of a planned outage during the first quarter of 2012.

For the twelve months ended December 31, 2013, the Thermal Energy Division's operating profit was $11.4 million, as compared to $9.1 million during the same period in 2012. The Windsor Locks Thermal Facility contributed $3.3 million, while the Sanger Thermal Facility contributed $7.9 million of operating profit during the twelve months ended December 31, 2013 as compared to $1.8 million and $6.8 million, respectively, during the same period in the prior year. Interest and other income for twelve months ended December 31, 2013 was $0.2 million as compared to $0.5 million during the same period in the prior year a decrease of $0.3 million resulting from lower equity income received from the Valley Power Thermal Facility. As a result of the stronger U.S. dollar, operating profit increased by $0.4 million. Detailed results of each facility are described below.

Windsor Thermal Locks Facility

For the twelve months ended December 31, 2013, the Windsor Locks Thermal Facility sold 623.0 billion lbs of steam as compared to 602.2 billion lbs of steam in the comparable period of 2012.

Energy/Steam sales at the Windsor Locks Thermal Facility were $17.7 million which was consistent with the same period in 2012. The increase in energy/steam sales is attributed to a higher average price for gas and higher steam production driven by increased customer demand, partially offset by the lower electrical energy production as a result of the newly installed, smaller, more efficient Titan turbine. Natural gas costs for the period were $11.2 million as compared to $11.7 million in the same period in 2012. The decrease in natural gas costs is due to a $2.9 million decrease in the volume of gas consumed as a result of the newly installed, smaller Titan turbine offset by a $2.4 million increase in the average landed cost of natural gas.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the twelve months ended December 31, 2013, net energy sales at the Windsor Locks Thermal Facility totalled $6.5 million, as compared to $6.0 million during the same period in 2012, an increase of $0.5 million.

Operating expenses, excluding natural gas costs were $3.7 million as compared to $4.5 million in the same period in 2012. The decrease in operating expenses was primarily due to the reduced electricity purchases. In 2012, during the planned shutdown, the Windsor Locks Thermal Facility was required to purchase all the electricity requirements for its customer; this additional expense was not required in the current year. The Windsor Locks Thermal Facility's resulting net operating income for the twelve months ended December 31, 2013 was $3.3 million as compared to $1.8 million in the same period in 2012, an increase of $1.5 million.

Sanger Thermal Facility

The Sanger Thermal Facility's operating profit was driven by energy/steam sales of $16.9 million as compared to $12.4 million in the same period in 2012, an increase of $4.5 million. The increase in energy/steam sales is primarily a result of the Sanger Thermal Facility being offline due to a planned outage for three months during the same period in the prior year. The return to operation resulted in an increase of $1.5 million due to increased electrical energy production, and $3.0 million in increased billing rates, as compared to the same period in 2012. Capacity revenues remained unchanged at $8.3 million. Gas costs for the period were $6.0 million as compared to $2.9 million in the same period in 2012. The increase in gas costs is due to an increase in the volume of natural gas consumed, and a 48% increase in the average cost of natural gas per MMBTU.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the twelve months ended December 31, 2013, net energy sales at the Sanger facility totalled $10.9 million, as compared to $9.5 million during the same period in 2012, an increase of $1.4 million.

Operating expenses, excluding natural gas costs were $4.9 million as compared to $4.1 million in the same period in 2012. The increase in operating expenses was due to the Sanger Thermal Facility operating for the twelve months ended December 31, 2013, as opposed to being offline for three months during the same period in 2012. The Sanger facility's resulting net operating income for the twelve months ended December 31, 2013 was $7.9 million, as compared to $6.8 million during the same period in 2012, an increase of $1.1 million.

| | | Three months ended December 31, 2013 | | | Three months ended December 31, 2012 | |
|---|---|---|---|---|---|---|
| | Windsor Locks | Sanger | Total | Windsor Locks | Sanger | Total |
| **Performance**(GW-hrs sold) | **28.8** | **35.6** | **64.4** | 35.3 | 35.3 | 70.6 |
| **Performance**(steam sales – billion lbs) | **161.3** | **—** | **161.3** | 175.3 | — | 175.3 |
| (all amounts in millions) | | | | | | |
| Revenue | | | | | | |
| Energy/steam sales | **$ 4.6** | **$ 3.9** | **$ 8.5** | **$ 5.0** | **$ 3.3** | **$ 8.3** |
| Less: | | | | | | |
| Cost of Sales – Fuel | **(3.1)** | **(1.5)** | **(4.6)** | (3.2) | (1.2) | (4.4) |
| Net Energy/Steam Sales | **$ 1.5** | **$ 2.4** | **$ 3.9** | $ 1.8 | $ 2.1 | $ 3.9 |
| Other revenue | **0.2** | **0.6** | **0.8** | 0.2 | 0.4 | 0.6 |
| Total net revenue | **$ 1.7** | **$ 3.0** | **$ 4.7** | $ 2.0 | $ 2.5 | $ 4.5 |
| **Expenses** | | | | | | |
| Operating expenses | **(0.8)** | **(1.2)** | **(2.0)** | (0.8) | (1.3) | (2.1) |
| Facility operating profit | **$ 0.9** | **$ 1.8** | **$ 2.7** | $ 1.2 | $ 1.2 | $ 2.4 |
| Interest and other income | | | **0.1** | | | 0.3 |
| Divisional operating profit | | | **$ 2.8** | | | $ 2.7 |

## 2013 Fourth Quarter Operating Results

Production data, revenue and expenses have been adjusted to remove the results of the EFW Facility which is now disclosed as discontinued operations. See Financial Statement note 20 for details.

For the three months ended December 31, 2013, the Thermal Energy Division produced 64.4 GW-hrs of electrical energy as compared to 70.6 GW-hrs of electrical energy in the comparable period of 2012. The decrease in electrical energy production at the Windsor Locks facility was primarily due to the installation of the new Titan turbine which is a smaller, more efficient turbine, sized to optimize the electricity and steam requirements of the steam host, and to minimize exposure of the facility to the ISO NE electricity market, compared to the larger Frame 6 turbine that was operating in previous years.

For the three months ended December 31, 2013, the Thermal Energy Division's operating profit was $2.8 million as compared to $2.7 million in the same period in 2012, an increase of $0.1 million. The Windsor Locks Thermal Facility contributed $0.9 million, while the Sanger Thermal Facility contributed $1.8 million of operating profit during the three months ended December 31, 2013 as compared to $1.2 million and $1.2 million, respectively during the same period in the prior year. Interest and other income for three months ended December 31, 2013 was $0.1 million as compared to $0.3 million during the same period in the prior year a decrease of $0.2 million resulting from lower equity income received from the Valley Power Thermal Facility. As a result of the stronger U.S. dollar operating profit increased by $0.2 million. Detailed results of each facility are described below.

Windsor Locks

For the three months ended December 31, 2013, the Windsor Locks Thermal Facility sold 161.3 billion lbs of steam as compared to 175.3 billion lbs of steam in the comparable period of 2012.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of $4.6 million which was consistent with the same period in 2012. Gas costs for the period were $3.1 million as compared to $3.2 million in the same period in 2012. The decrease in gas costs is a result of a 4.4% increase on the average landed cost of natural gas per MMBTU offset by a 14.0% decrease in the volume of natural gas consumed, as compared to the same period in 2012.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended December 31, 2013, net sales at the Windsor Locks Thermal Facility totalled $1.5 million, as compared to $1.8 million during the same period in 2012, a decrease of $0.3 million.

Operating expenses, excluding natural gas costs were $0.8 million which was consistent with the same period in 2012. The Windsor Locks Thermal Facility's resulting net operating income for the three months ended December 31, 2013 was $0.9 million as compared to $1.2 million in the same period in 2012, a decrease of $0.3 million.

Sanger

The Sanger Thermal Facility's operating profit was driven by energy/steam sales of $3.9 million as compared to $3.3 million in the same period in 2012, an increase of $0.6 million. The increase in energy/steam sales is attributed to $0.6 million in increased gas prices which is a pass through to customers as compared to the same period in 2012. Capacity revenues remained unchanged at $1.7 million. Gas costs for the period were $1.5 million as compared to $1.2 million in the same period in 2012. The increase in gas costs is due to an increase in the volume of natural gas consumed, and a 25% increase in the average cost of natural gas per MMBTU as compared to the same period in 2012.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended December 31, 2013, net energy sales at the Sanger Thermal Facility totalled $2.4 million, as compared to $2.1 million during the same period in 2012, an increase of $0.3 million.

Operating expenses, excluding natural gas costs were $1.2 million as compared to $1.3 million in the same period in 2012. The Sanger Thermal Facility's resulting net operating income for the three months ended December 31, 2013 was $1.8 million as compared to $1.2 million in the same period in 2012, an increase of $0.6 million.

## APCo: Development Division

The Development Division works to identify, develop and construct new power generating facilities, as well as to identify, and acquire, operating projects that would be complementary and accretive to APCo's existing portfolio. The Development Division is focused on projects within North America and is committed to working proactively with all stakeholders including local communities. APCo's approach to project development and acquisition is to maximize the utilization of internal resources while minimizing external costs. This allows projects to mature to the point where most major elements and uncertainties are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a power purchase agreement, obtaining the required financing commitments to develop the project, completion of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that APCo will begin construction or execute an acquisition agreement.

## Projects Currently in Development

APCo's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of power purchase agreements. The projects are as follows:

| Project Name | Location | Size (MW) | | Estimated Capital Cost | Commercial Operation | PPA Term | Production GW-hrs |
|---|---|---|---|---|---|---|---|
| Chaplin Wind [1] | Saskatchewan | 177 | $ | 340.0 | 2016 | 25 | 720.0 |
| Amherst Island [2] | Ontario | 75 | $ | 230.0 | 2015 | 20 | 247.0 |
| Val Eo - Phase I [1, 6, 7] | Quebec | 24 | $ | 70.0 | 2015 | 20 | 66.0 |
| Morse Wind [3, 4] | Saskatchewan | 23 | $ | 81.3 | 2015 | 20 | 108.0 |
| Bakersfield Solar[1, 8] | California | 20 | $ | 62.2 | 2015 | 20 | 53.3 |
| St. Damase - Phase I [1, 5, 7] | Quebec | 24 | $ | 65.0 | 2014 | 20 | 78.7 |
| Cornwall Solar [1, 2] | Ontario | 10 | $ | 45.0 | 2014 | 20 | 14.4 |
| **Total** | | **353** | **$** | **893.5** | | | **1,287.4** |

1 PPA signed

2 FIT contract awarded

3 Two 10 MW PPAs; one 5MW PPA

4 Comprised of three projects that are connected geographically and will be built simultaneously. All three projects were awarded PPAs under the province's Green Options Partner Program ("GOPP").

5 The St. Damase project is being developed in two phases: Phase I of the project (24MW) will be erected in 2014 and the 101MW Phase II of the project will be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

6 The Val Eo project is being developed in two phases: Phase I of the project (24MW) will be erected in 2015 and the 101 MW Phase II of the project will be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

7 Size, Estimated Capital Costs, Commercial Operation Date, PPA Term and Production refer solely to Phase I of the St. Damase and Val-Eo wind projects.

8 Total cost the project is expected to be U.S $58.5 million.

## Chaplin Wind Project

In the first quarter of 2012, APCo entered into a 25 year PPA with SaskPower for development of a 177 MW wind power project in the rural municipality of Chaplin, Saskatchewan, 150 km west of Regina, Saskatchewan.

The project has a targeted commercial operation date of December, 2016. The facility will be constructed at an estimated capital cost of $340 million and consist of approximately 77 multi-megawatt wind turbines. The project is expected to generate first full year EBITDA of $36.5 million. The 25 year PPA features a rate escalation provision of 0.6% throughout the term of the agreement. The project will take advantage of its favourable location by interconnecting with a nearby 138Kv line and will be compliant with SaskPower's latest interconnection requirements.

The Environmental Impact Assessment was submitted in third quarter of 2013 to the Environmental Assessment Branch, Saskatchewan Environment. Screening was completed, and a proposed layout was requested in order to provide a final determination. A supplemental report was submitted in the fourth quarter of 2013 to address the questions identified during the screening process and the project is awaiting a response from the Environment Assessment Branch. As a result of continuing development work, the expected capital costs of the project have been reduced to $340 million from the original estimate of $355 million. To optimize the returns associated with the project, APCo intends to enter into a partnership agreement using a similar structure to what was utilized in the development of the Red Lily I facility.

## Amherst Island Wind Project

The Amherst Island wind project is located on Amherst Island near the village of Stella, approximately 15 kilometres southwest of Kingston, Ontario. In February 2011, the 75 MW project was awarded a FIT contract by the OPA as part of the second round of the OPA's FIT program.

The Amherst Island wind project is currently contemplated to use Class III wind turbine generator technology. APCo forecasts that the available wind resource could produce approximately 247 GW-hrs of electrical energy annually, depending upon the final turbine selection for the project. Total capital costs for the facility are currently estimated to be $230 million. The financing of the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied. Environmental studies and engineering are underway.

The Renewable Energy Approval ("REA") application was submitted in April 2013 and was posted to the environmental registry in early January 2014. The REA is now anticipated to be received at the beginning of the third quarter of 2014. Subject to receipt of the REA approval as expected, construction is expected to commence shortly thereafter; with a planned construction time frame of 12 to 18 months. Completion is targeted to occur in late 2015 or early 2016.

## Morse Wind Project

The Morse wind project is comprised of three contiguous projects with 25 MW of aggregate installed generating capacity. The project is to be constructed near Morse, Saskatchewan, approximately 180 km west of Regina. It is contemplated that the project will have additional land under lease or option in order to facilitate future expansion.

Based on the award of 25MW under Saskatchewan's Green Options Partner Program, SaskPower has offered APCo a 20 year contract for the procurement of 23MW of wind generation to match the nameplate capacity of the proposed turbines.

APCo executed an asset purchase agreement with a local developer, Kineticor, to acquire assets related to two adjacent 10 MW wind energy development projects in Saskatchewan and a further 5 MW was developed by APCo independently. All of the individual projects comprising the Morse wind project were selected by SaskPower in accordance with the SaskPower Green Options Partners Program.

The total annual energy production for the Morse Wind Project has increased from 93.0 GW-hrs to 108.0 GW-hrs due to final turbine selection and increased hub height. Accordingly, the capital cost to construct the Morse wind project has also increased and is currently estimated to be $81.3 million, inclusive of acquisition costs. The contract rate is set at $104.02 per MW-hr for the first full year of operations, which APCo expects to occur in 2015, with an annual escalation provision of 2% over the expected 20 year term.

The provincial environmental assessment of the site was completed in the first quarter of 2012 and submitted to the provincial Environmental Assessment agency. In April 2012, the project was deemed a "non-development" by the Provincial Environmental Assessment Branch thereby not requiring further environmental assessment review.

## Quebec Community Wind Projects

In December 2010, APCo, in partnership with Société en Commandite Val-Éo, a community cooperative with a development project located in the Lac Saint-Jean region of Quebec, and in partnership with the community of Saint-Damase, were awarded PPAs for the construction of two wind power projects in the Province of Quebec using ENERCON wind turbines. Both projects will represent phase one in the potential development of a larger second phase.

## Saint-Damase

Phase one of the Saint-Damase wind project is located in the local municipality of Saint-Damase, which is within the regional municipality of les Maskoutains. The project is a 24MW facility located near St. Damase, Quebec in a partnership with the Municipality of Saint-Damase. The Saint-Damase wind project has signed a 20 year PPA with Hydro Quebec and has projected capital costs of $65 million. On June 25, 2013, the partnership executed an interconnection agreement with Hydro Quebec. The permitting and the environmental impact assessment are ongoing and the construction of the first project phase is planned for the early second quarter of 2014, with commercial operation for the project expected to commence in late 2014.

APCo's interest in the project will not be less than 50%. The project's social acceptance is strong, and about 50 jobs will be created during construction. The environmental impact assessment for the project has been reviewed and has received the provincial minister's decree allowing the project to proceed with construction. APCo has entered into an agreement for the supply of wind turbines with Enercon Canada Inc. It is believed that the first 24MW phase of the Saint-Damase wind project will qualify as Canadian Renewable conservation expense and therefore the project will be entitled to a refundable tax credit equal to approximately $20.5 million. It is contemplated that a request for a PPA in respect of Phase II of the project will be submitted to Hydro Quebec pursuant to its current request for proposals and if successful would proceed based on the results achieved in Phase I.

## Val-Éo

Phase one of the Val-Éo wind project is located in the local municipality of Saint-Gideon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APCo. The first 24 MW phase of the project is expected to be comprised of eight wind turbines, producing approximately 66.0GW-hr annually. Construction of the first 24 MW phase of the project is expected to begin in early 2015 with commercial operations commencing in late 2015. The second phase of the project would entail the development of an additional 106 MW. The permitting and the Environmental Impact Assessment are ongoing with a projected provincial minister's decree at the end of 2014.

APCo's interest in the project is subject to final negotiations with the Val-Éo community cooperative but, in any event, will not be less than 25%. It is believed that the first 24MW phase of the Val-Eo wind project will qualify as Canadian Renewable Conservation Expense and therefore the project will be entitled to a refundable tax credit equal to approximately $22.0 million. It is contemplated that a request for a PPA in respect of Phase II of the project will be submitted to Hydro Quebec pursuant to its current request for proposals and if successful would proceed based on the results achieved in Phase I.

## Cornwall Solar Project

In the first quarter of 2012, APCo acquired all of the issued and outstanding shares of Cornwall Solar which owns the rights to develop the Cornwall Project, a 10 MW solar project located near Cornwall, Ontario. In addition to the Cornwall Project, APCo has acquired an option to acquire ten additional Ontario based solar projects.

The Cornwall Project has been granted a FIT contract by the OPA, with a 20 year term and a rate of $443/MW-hr, resulting in expected initial annual revenues of approximately $6.2 million. The Cornwall Project contemplates the use of a ground-mounted PV array system, installed on two parcels of leased land totalling approximately 138 acres.

The Cornwall Project received its Renewable Energy Approval on January 15, 2013 and its Notice to Proceed on April 29, 2013. Construction of the project began during the second quarter of 2013 with substantial completion expected by the end of the first quarter of 2014 and commercial operation expected to commence in the second quarter of 2014. After completion of the design and start of construction, improvements in engineering layout and module capacity have led to an increase in annual energy production forecast from 13.4 GW-hrs/year to 14.4 GW-hrs/year. Generation in excess of 13.4 GW-hrs/year is paid to the original developer after minimum return thresholds are achieved by APCo.

### Bakersfield Solar Project

APCo has entered into an agreement for the continuing development of a 20 MWac solar powered generating station located in Kern County, California. Following commissioning, the Bakersfield solar project is expected to generate 53.3 GW-hrs of energy per year. All energy from the project will be sold to PG&E pursuant to a 20 year agreement with expected first full year revenues of U.S. $4.7 million. APCo plans to enter into a partnership agreement with a third party (the "Tax Partner") pursuant to which the Tax Partner will receive the majority of the tax attributes associated with the project. It is anticipated that the total expected capital costs for the project of U.S. $58.5 million will be funded as to 55% by APCo and the balance by the Tax Partner. Subject to receipt of final permits and approvals and reaching satisfactory agreement with the Tax Partner, construction of the project is anticipated to commence in the second quarter of 2014 with a commercial operations date expected to occur in late 2014.

## Liberty Utilities

Liberty Utilities is a national diversified rate regulated utility providing electricity, natural gas, water distribution and wastewater collection utility services in the U.S. Liberty Utilities' strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. Liberty Utilities believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing community connections.

| Utility System Type | December 31, 2013 | | December 31, 2012 | |
|---|---|---|---|---|
| | Assets | Connections | Assets | Connections |
| | U.S. $ (millions) | | U.S. $ (millions) | |
| Electricity | $ 276.6 | 91,600 | $ 254.3 | 91,200 |
| Natural Gas | 661.5 | 291,800 | 394.8 | 175,500 |
| Water and Wastewater | 233.0 | 97,400 | 205.4 | 78,000 |
| Total | $ 1,171.1 | 480,800 | $ 854.5 | 344,700 |
| Accumulated Deferred Income Taxes | $ 66.5 | | $ 53.5 | |

Liberty Utilities reports the performance of its utility operations by geographic region – West, Central, and East

The Liberty Utilities (West) region is comprised of regulated electrical and water distribution and wastewater collection utility systems and serves approximately 115,800 connections in the states of Arizona and California.

The Liberty Utilities (Central) region is comprised of regulated natural gas and water distribution and wastewater collection utility systems and serves approximately 115,000 connections located in the states of Arkansas, Illinois, Iowa, Missouri, and Texas.

The Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems and serves approximately 250,000 connections located in the states of Georgia, Massachusetts, and New Hampshire.

## Liberty Utilities: West Region

| | Year ended December 31, 2013 | 2012 |
|---|---|---|
| **Average Active Electric Connections For The Period** | | |
| Residential | 41,200 | 41,300 |
| Commercial and Industrial | 5,500 | 5,600 |
| **Total Average Active Electric Connections For The Period** | **46,700** | **46,900** |
| **Average Active Water Connections For The Period** | | |
| Wastewater connections | 30,700 | 29,700 |
| Water distribution connections | 33,900 | 33,100 |
| **Total Average Active Water Connections For The Period** | **64,600** | **62,800** |
| **Customer Usage (GW-hrs)** | | |
| Residential | 281.3 | 273.6 |
| Commercial and Industrial | 277.1 | 279.1 |
| **Total Customer Usage (GW-hrs)** | **558.4** | **552.7** |
| **Gallons Provided** | | |
| Wastewater treated (millions of gallons) | 1,660 | 1,648 |
| Water sold (millions of gallons) | 5,072 | 5,080 |
| **Total Gallons Provided** | **6,732** | **6,728** |

The Liberty Utilities (West) region's increase in average water and wastewater connections during the period is primarily due to development within the service territory. During the twelve months ended December 31, 2013, the Liberty Utilities (West) region provided approximately 5,072 million gallons of water to its customers and treated approximately 1,660 million gallons of wastewater as compared to 5,080 million gallons of water and 1,648 million gallons of wastewater during the same period in 2012.

For the twelve months ended December 31, 2013, electricity usage at the CalPeco Electric System totalled 558.4 GW-hrs, as compared to 552.7 GW-hrs for the same period in 2012, an increase of 5.7 GW-hrs or 1.1%. This increase in usage was primarily due to colder weather experienced in the first quarter of 2013 as compared to warmer weather experienced in the same period a year ago. Under the base rate revenue decoupling mechanism approved by the California Public Utilities Commission ("CPUC"), which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues will not be impacted by fluctuations in customer demand due to the variations in the weather conditions and changes in the number of customers. Instead, the CalPeco Electric System is required to record 1/12 of its annual base rate revenue requirement each month. The electricity commodity continues to be passed through to the CalPeco Electric System's customers according to their consumption.

| | Year ended December 31, 2013 U.S. $ (millions) | Year ended December 31, 2012 U.S. $ (millions) | Year ended December 31, 2013 Can $ (millions) | Year ended December 31, 2012 Can $ (millions) |
|---|---|---|---|---|
| Water Assets for regulatory purposes | **179.3** | 181.3 | | |
| Electricity Assets for regulatory purposes | **175.5** | 165.9 | | |
| **Revenue** | | | | |
| Utility electricity sales and distribution | **$ 75.5** | $ 71.9 | **$ 77.8** | $ 71.7 |
| Wastewater treatment | **18.1** | 18.3 | **18.7** | 18.3 |
| Water distribution | **19.8** | 19.0 | **20.4** | 19.0 |
| Other Revenue | **—** | 0.2 | **—** | 0.2 |
| Total Revenue | **$ 113.4** | $ 109.4 | **$ 116.9** | $ 109.2 |
| Less: | | | | |
| Cost of Sales – Electricity | **(38.6)** | (44.0) | **(39.8)** | (43.9) |
| Net Utility Sales | **$ 74.8** | $ 65.4 | **$ 77.1** | $ 65.3 |
| **Expenses** | | | | |
| Operating expenses | **(35.6)** | (35.6) | **(36.7)** | (35.6) |
| Other income | **1.4** | 2.1 | **1.4** | 2.1 |
| **Divisional operating profit** | **$ 40.6** | $ 31.9 | **$ 41.8** | $ 31.8 |

## 2013 Annual Operating Results

The Liberty Utilities (West) region has investments in water and wastewater distribution assets for regulatory purposes of U.S. $179.3 million  and electricity assets for regulatory purposes of U.S.$175.5 million as at December 31, 2013, as compared to U.S.  $181.3 million and U.S .$165.9 million, respectively as at December 31, 2012.

For the twelve months ended December 31, 2013, the Liberty Utilities (West) region's revenue totalled U.S. $113.4 million as compared to U.S. $109.4 million during the same period in 2012, an increase of U.S. $4.0 million or 3.7%.

For the twelve months ended December 31, 2013, the Liberty Utilities (West) region's revenue from utility electricity sales totalled U.S. $75.5 million as compared to U.S. $71.9 million during the same period in 2012, an increase of U.S. $3.6 million or 5.0%.  This increase in revenues was primarily due to an increase in base revenue requirement approved in the most recent rate case that became effective January 1, 2013 and milder winter and spring weather that occurred in the first part of 2012.  Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues will not be impacted by fluctuations in customer demand due to the variations in weather conditions and changes in the number of customers.

For the twelve months ended December 31, 2013, revenue from wastewater treatment and water distribution totalled U.S. $18.1 million and U.S. $19.8 million respectively, as compared to U.S. $18.3 million and U.S. $19.0 million, respectively, during the same period in 2012. The total wastewater treatment and water distribution revenue increase was due to increased connection counts, which increased fixed and usage revenue.

For the twelve months ended December 31, 2013, fuel and purchased power costs for the Liberty Utilities (West) region totalled U.S $38.6 million , as compared with U.S. $44.0 million for the same period in 2012.  The overall electricity purchase costs experienced a decrease of U.S. $5.4 million primarily as a result of a change in rates effective January 1, 2013 which refunds an over-collection of electricity costs from the prior fiscal period

The purchase of electricity by the Liberty Utilities (West) region is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers.  As a result, the Liberty Utilities (West) region compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results.  For the twelve months ended December 31, 2013, net utility sales for the Liberty Utilities (West) region were U.S. $74.8 million, as compared to U.S. $65.4 million during the same period in 2012, an increase of $9.4 million, or 14.4% .

For the twelve months ended December 31, 2013, operating expenses totalled U.S. $35.6 million, which was consistent with the same period in 2012.

For the twelve months ended December 31, 2013, the Liberty Utilities (West) region's operating profit was U.S $40.6 million as compared to U.S $31.9 million in the same period in 2012, an increase of U.S.$ $8.7 million, or 27.3%.

Measured in Canadian dollars, the Liberty Utilities (West) region's operating profit was $41.8 million as compared to $31.8 million in the same period in 2012.

| | Three months ended December 31, | |
|---|---|---|
| | **2013** | **2012** |
| **Average Active Electric Connections For The Period** | | |
| Residential | 41,600 | 41,300 |
| Commercial and Industrial | 5,500 | 5,600 |
| **Total Average Active Electric Connections For The Period** | **47,100** | **46,900** |
| **Average Active Number of Water Connections For The Period** | | |
| Wastewater connections | 30,900 | 30,100 |
| Water distribution connections | 34,100 | 33,400 |
| **Total Average Active Water Connections For The Period** | **65,000** | **63,500** |
| **Customer Usage (GW-hrs)** | | |
| Residential | 77.0 | 72.2 |
| Commercial and Industrial | 77.2 | 81.5 |
| **Total Customer Usage (GW-hrs)** | **154.2** | **153.7** |
| **Gallons Provided** | | |
| Wastewater treated (millions of gallons) | 418 | 423 |
| Water sold (millions of gallons) | 1,277 | 1,256 |
| **Total Gallons Provided** | **1,695** | **1,679** |

For the three months ended December 31, 2013, the Liberty Utilities (West) region's electricity usage totalled 154.2 GW-hrs, as compared to 153.7 GW-hrs for the same period in 2012, an increase of 0.5 GW-hrs. Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues will not be impacted by fluctuations in customer demand due to the variations in the weather conditions and changes in the number of customers. Instead, the CalPeco Electric System is required to record 1/12 of its annual base rate revenue requirement each month. The electricity commodity continues to be passed through to the CalPeco Electric System's customers according to their consumption.

During the three months ended December 31, 2013, the Liberty Utilities (West) region provided approximately 1,277 million gallons of water to its customers and treated approximately 418 million gallons of wastewater, as compared to 1,256 gallons of water and 423 gallons of wastewater during the same period in 2012.

| | Three months ended December 31, | | Three months ended December 31, | |
|---|---|---|---|---|
| | **2013 U.S. $ (millions)** | 2012 U.S. $ (millions) | **2013 Can $ (millions)** | 2012 Can $ (millions) |
| **Revenue** | | | | |
| Utility electricity sales and distribution | **$ 19.8** | $ 19.5 | **$ 20.7** | $ 19.3 |
| Wastewater treatment | **4.2** | 4.7 | **4.4** | 4.7 |
| Water distribution | **5.2** | 4.5 | **5.5** | 4.5 |
| Other Revenue | **—** | — | **—** | — |
| | **$ 29.2** | $ 28.7 | **$ 30.6** | $ 28.5 |
| Less: | | | | |
| Cost of Sales – Electricity | **(10.5)** | (11.5) | **(11.0)** | (11.4) |
| Net Utility Sales | **$ 18.7** | $ 17.2 | **$ 19.6** | $ 17.1 |
| **Expenses** | | | | |
| Operating expenses | **(8.4)** | (9.3) | **(8.9)** | (9.4) |
| Other income | **0.2** | 1.1 | **0.3** | 1.1 |
| **Division operating profit** | **$ 10.5** | $ 9.0 | **$ 11.0** | $ 8.8 |

## 2013 Fourth Quarter Operating Results

For the three months ended December 31, 2013, the Liberty Utilities (West) region's revenue totalled U.S. $29.2 million as compared to U.S.$28.7 million during the same period in 2012, an increase of U.S. $0.5 million or 1.7%.

For the three months ended December 31, 2013, the Liberty Utilities (West) region's revenue from utility electricity sales totalled U.S. $19.8 million as compared to U.S. $19.5 million during the same period in 2012, an increase of U.S. $0.3 million or 1.5%. This increase in revenues was primarily due to an increase in base revenue requirements approved in the most recent rate case that became effective January 1, 2013. Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues will not be impacted by fluctuations in customer demand due to the variations in weather conditions and changes in the number of customers.

For the three months ended December 31, 2013 revenue from wastewater treatment and water distribution totalled U.S. $4.2 million and U.S. $5.2 million, respectively, as compared to U.S. $4.7 million and U.S. $4.5 million, respectively, during the same period in 2012. The total wastewater treatment and water distribution revenue was primarily due to an increase in average connection counts, as compared to the same period in 2012.

For the three months ended December 31, 2013 fuel and purchased power costs for the Liberty Utilities (West) region totalled U.S $10.5 million, as compared with U.S. $11.5 million for the same period in 2012, a decrease of $1.0 million. The overall electricity purchase costs experienced a decrease of U.S. $1.0 million primarily as a result of a change in rates effective January 1, 2013 which refunds an over-collection of electricity costs from the prior fiscal period.

The purchase of electricity by the Liberty Utilities (West) region is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the Liberty Utilities (West) region compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the three months ended December 31, 2013 net utility sales for the Liberty Utilities (West) region were U.S. $18.7 million, as compared to U.S. $17.2 million during the same period in 2012, an increase of $1.5 million or 8.7%.

For the three months ended December 31, 2013 operating expenses totalled U.S. $8.4 million, as compared to U.S. $9.3 million during the same period in 2012.

For the three months ended December 31, 2013, the Liberty Utilities (West) region's operating profit was U.S. $10.5 million as compared to U.S. $9.0 million in the same period in 2012, an increase of U.S. $1.5 million or 16.7%.

Measured in Canadian dollars, the Liberty Utilities (West) region's operating profit was $11.0 million as compared to $8.8 million in the same period in 2012.

## Liberty Utilities: Central Region

| | Year ended December 31, 2013 | 2012 |
|---|---|---|
| **Average Active Natural Gas Connections For The Period** | | |
| Residential | 71,300 | 71,500 |
| Commercial and Industrial | 9,200 | 9,500 |
| **Total Average Active Natural Gas Connections For The Period** | **80,500** | **81,000** |
| **Average Active Water Connections For The Period** | | |
| Wastewater connections | 5,900 | 5,800 |
| Water distribution connections | 21,900 | 5,300 |
| **Total Average Active Water Connections For The Period** | **27,800** | **11,100** |
| **Customer Usage (MMBTU)** | | |
| Residential | 5,187,000 | 1,307,000 |
| Commercial and Industrial | 3,555,000 | 1,093,000 |
| **Total Customer Usage (MMBTU)**[1] | **8,742,000** | **2,400,000** |
| **Gallons Provided** | | |
| Wastewater treated (millions of gallons) | 374 | 372 |
| Water sold (millions of gallons)[2] | 3,090 | 383 |
| **Total Gallons Provided** | **3,464** | **755** |

1 Represents MMBTU since August 1, 2012 acquisition date

2 Water distribution utility was acquired on February 1, 2013

The Liberty Utilities (Central) region acquired the Pine Bluff Water System on February 1, 2013 and the Midstates Gas System on August 1, 2012, and accordingly, the twelve month results for 2012 are not comparative.

For the twelve months ended December 31, 2013, the Liberty Utilities (Central) region natural gas distribution sales totalled 8,742,000 MMBTU as compared to 2,400,000 MMBTU during the same period in 2012, an increase of 6,342,000 MMBTU.

During the twelve months ended December 31, 2013, the Liberty Utilities (Central) region provided approximately 3,090 million gallons of water to its customers, and treated approximately 374 million gallons of wastewater, as compared to 383 million gallons of water and 372 million gallons of wastewater during the same period in 2012.

As a result of the acquisition of the Pine Bluff Water System on February 1, 2013 the number of water connections in the region increased by approximately 17,700. During the twelve months ended December 31, 2013, the amount of water sold correspondingly increased by 2,613 million gallons.

| | Year ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2013 U.S. $ (millions)** | 2012 U.S. $ (millions) | **2013 Can $ (millions)** | 2012 Can $ (millions) |
| Natural Gas Assets for regulatory purposes | **148.1** | 131.4 | | |
| Water Assets for regulatory purposes | **53.7** | 24.1 | | |
| **Revenue** | | | | |
| Utility natural gas sales and distribution[1] | **$ 73.3** | $ 24.8 | **$ 75.5** | $ 24.6 |
| Wastewater treatment | **5.8** | 5.6 | **6.0** | 5.6 |
| Water distribution | **11.9** | 3.5 | **12.2** | 3.5 |
| Gas transportation | **3.3** | 1.2 | **3.4** | 1.2 |
| | **$ 94.3** | $ 35.1 | **97.1** | $ 34.9 |
| Less: | | | | |
| Cost of Sales – Natural Gas[1] | **(44.7)** | (13.8) | (46.0) | (13.6) |
| Net utility sales | **$ 49.6** | $ 21.3 | **$ 51.1** | $ 21.3 |
| **Expenses** | | | | |
| Operating expenses | **(26.6)** | (13.1) | **(27.4)** | (13.1) |
| Interest and other income | **0.4** | — | **$ 0.4** | $ — |
| **Divisional operating profit** | **$ 23.4** | $ 8.2 | **$ 24.1** | $ 8.2 |

[1] Represents Natural Gas revenue and gas costs since August 1, 2012 acquisition date.

## 2013 Annual Operating Results

The Liberty Utilities (Central) region has investments in natural gas distribution assets for regulatory purposes of U.S. $148.1 million and water distribution assets for regulatory purposes of U.S. $53.7 million as at December 31, 2013, as compared to U.S $131.4 million and U.S. $24.1 million, respectively as at December 31, 2013. The increase in natural gas distribution assets for regulatory purposes is primarily related to pipe expansion and replacement activities and system implementations, while the increase in water assets for regulatory purposes is primarily a result of the Pine Bluff Water System acquisition.

For the twelve months ended December 31, 2013, the Liberty Utilities (Central) region's revenue totalled U.S. $94.3 million as compared to U.S. $35.1 million during the same period in 2012, an increase of U.S. $59.2 million. The increase in revenue is primarily attributed to the addition of the natural gas distribution assets acquired on August 1, 2012 and the Pine Bluff Water System acquired on February 1, 2013.

For the twelve months ended December 31, 2013, the Liberty Utilities (Central) region's revenue from natural gas sales and distribution totalled U.S. $73.3 million as compared to U.S. $24.8 million during the same period in 2012, an increase of U.S. $48.5 million.

For the twelve months ended December 31, 2013, the Liberty Utilities (Central) region's revenue from gas transportation sales totalled U.S. $3.3 million as compared to U.S. $1.2 million during the same period in 2012, an increase of U.S. $2.1 million . The increase in transportation revenue is primarily attributed to the addition of the natural gas distribution assets acquired on August 1, 2012.

For the twelve months ended December 31, 2013, revenue from wastewater treatment and water distribution totalled U.S. $5.8 million and U.S. $11.9 million, respectively, as compared to U.S. $5.6 million and U.S. $3.5 million, respectively, during the same period in 2012. The increase in water distribution revenue is primarily attributed to the addition of the Pine Bluff Water System.

For the twelve months ended December 31, 2013, natural gas purchases for the Liberty Utilities (Central) region's natural gas utility totalled U.S $44.7 million , as compared with U.S. $13.8 million for the same period in 2012. The overall natural gas purchase costs experienced an increase of U.S. $30.9 million.

The purchase of natural gas by the Liberty Utilities (Central) region is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the division compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the twelve months ended December 31, 2013, net utility sales from natural gas sales and distribution for the Liberty Utilities (Central) region totalled U.S. $49.6 million as compared to U.S. $21.3 million during the same period in 2012, an increase of U.S. $28.3 million. The increase in net utility sales is primarily due to the division reporting a full year of results in 2013 compared to partial year results in the previous year.

For the twelve months ended December 31, 2013, operating expenses, excluding natural gas purchases, totalled U.S. $26.6 million, as compared to U.S. $13.1 million during the same period in 2012. The increase in operating expenses can be primarily attributed to the addition of the natural gas distribution assets on August 1, 2012 and the Pine Bluff Water System acquired on February 1, 2013.

For the twelve months ended December 31, 2013, the Liberty Utilities (Central) region's operating profit was U.S. $23.4 million as compared to U.S. $8.2 million in the same period in 2012, an increase of U.S. $15.2 million primarily attributed to the aforementioned acquisitions.

Measured in Canadian dollars, the Liberty Utilities (Central) region's operating profit was $24.1 million as compared to $8.2 million in the same period in 2012.

| | Three months ended December 31, | |
|---|---|---|
| | 2013 | 2012 |
| **Average Active Natural Gas Connections For The Period** | | |
| Residential | 70,300 | 72,000 |
| Commercial and Industrial | 9,100 | 9,600 |
| **Total Average Active Natural Gas Connections For The Period** | **79,400** | **81,600** |
| **Average Active Water Connections For The Period** | | |
| Wastewater connections | 6,000 | 5,800 |
| Water distribution connections | 21,800 | 5,300 |
| **Total Average Active Water Connections For The Period** | **27,800** | **11,100** |
| **Customer Usage (MMBTU)** | | |
| Residential | 1,308,000 | 1,160,000 |
| Commercial and Industrial | 1,147,000 | 841,000 |
| **Total Customer Usage (MMBTU)** | **2,455,000** | **2,001,000** |
| **Gallons Provided** | | |
| Wastewater treated (millions of gallons) | 88.5 | 94.6 |
| Water sold (millions of gallons) | 803.6 | 97.3 |
| **Total Gallons Provided** | **892.1** | **191.9** |

The Liberty Utilities (Central) region acquired the Pine Bluff Water System water distribution utility on February 1, 2013, and accordingly, there are no results for this utility for the corresponding period in 2012.

For the three months ended December 31, 2013, the Liberty Utilities (Central) region natural gas distribution sales totalled 2,455,000 MMBTU as compared to 2,001,000 during the same period in 2012, an increase of 454,000 MMBTU or 22.7%.

During the three months ended December 31, 2013, the Liberty Utilities (Central) region provided approximately 803.6 million gallons of water to its customers, and treated approximately 88.5 million gallons of wastewater, as compared to 97.3 million gallons of water and 94.6 million gallons of wastewater during the same period in 2012.

As a result of the acquisition of the Pine Bluff Water System on February 1, 2013 the number of water connections in the region increased by 17,700. During the three months ended December 31, 2013, the amount of water sold also correspondingly increased by 698 million gallons.

| | Three months ended December 31, | | Three months ended December 31, | |
|---|---|---|---|---|
| | **2013 U.S. $ (millions)** | 2012 U.S. $ (millions) | **2013 Can $ (millions)** | 2012 Can $ (millions) |
| **Revenue** | | | | |
| Utility natural gas sales and distribution | **$ 22.5** | $ 19.7 | **$ 23.8** | $ 19.6 |
| Wastewater treatment | **1.5** | 1.4 | **1.5** | 1.6 |
| Water distribution | **3.1** | 0.6 | **3.2** | 0.5 |
| Gas Transportation | 0.9 | 0.8 | 0.9 | 0.8 |
| | **28.0** | 22.5 | **29.4** | 22.5 |
| Less: | | | | |
| Cost of Sales – Natural Gas | **(14.2)** | (12.0) | **(15.2)** | (11.9) |
| Net utility sales | 13.8 | 10.5 | 14.2 | 10.6 |
| **Expenses** | | | | |
| Operating expenses | **(7.2)** | (6.3) | **(7.6)** | (6.3) |
| Other income | **0.2** | — | **0.2** | — |
| **Division operating profit** | **$ 6.8** | $ 4.2 | **$ 6.8** | $ 4.3 |

## 2013 Fourth Quarter Operating Results

For the three months ended December 31, 2013, the Liberty Utilities (Central) region's revenue totalled U.S. $28.0 million as compared to U.S. $22.5 million during the same period in 2012, an increase of U.S. $5.5 million. The increase in revenue can be primarily attributed to the addition of the Pine Bluff Water System on February 1, 2013 and the increased natural gas sales and distribution discussed below.

For the three months ended December 31, 2013, the Liberty Utilities (Central) region's revenue from natural gas sales and distribution totalled U.S. $22.5 million as compared to U.S. $19.7 million during the same period in 2012, an increase of U.S. $2.8 million or 14.2%.

For the three months ended December 31, 2013, the Liberty Utilities (Central) region's revenue from gas transportation sales totalled U.S. $0.9 million as compared to U.S. $0.8 million during the same period in 2012, an increase of U.S. $0.1 million.

For the three months ended December 31, 2013, revenue from wastewater treatment and water distribution totalled U.S. $1.5 million and $3.1 million , as compared to U.S. $1.4 million and $0.6 million during the same period in 2012. The increase in total wastewater treatment and water distribution revenue can be primarily attributed to the addition of the Pine Bluff Water System.

For the three months ended December 31, 2013 natural gas purchases for the Liberty Utilities (Central) region's natural gas utility totalled U.S $14.2 million, as compared with U.S. $12.0 million for the same period in 2012, an increase of $2.2 million.

The purchase of natural gas by the Liberty Utilities (Central) region is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the division compares 'net utility sales' (utility sales after commodity costs) as a more appropriate measure of the division's results. For the three months ended December 31, 2013, net utility sales from natural gas sales and distribution for the Liberty Utilities (Central) region totalled U.S. $13.8 million as compared to U.S. $10.5 million during the same period in 2012, an increase of U.S. $3.3 million, or 31.4%.

For the three months ended December 31, 2013, operating expenses, excluding natural gas purchases, totalled U.S. $7.2 million, as compared to U.S. $6.3 million during the same period in 2012. The increase in operating expenses is primarily attributed to the acquisition of the Pine Bluff Water System on February 1, 2013.

For the three months ended December 31, 2013, the Liberty Utilities (Central) region's operating profit was U.S. $6.8 million as compared to U.S. $4.2 million in the same period in 2012, an increase of U.S. $2.6 million.

Measured in Canadian dollars, the Liberty Utilities (Central) region's operating profit was $6.8 million as compared to $4.3 million in the same period in 2012.

## Liberty Utilities East Region:

| | Year ended December 31, | |
|---|---|---|
| | **2013** | **2012** |
| **Average Active Natural Gas Connections** | | |
| Residential | 178,800 | 74,000 |
| Commercial and Industrial | 17,200 | 8,800 |
| **Total Average Active Natural Gas Connections** | **196,000** | **82,800** |
| **Average Active Electric Connections** | | |
| Residential | 36,800 | 36,200 |
| Commercial and Industrial | 6,500 | 6,500 |
| **Total Average Active Electric Connections** | **43,300** | **42,700** |
| **Customer Usage (GW-hrs)** | | |
| Residential | 304.6 | 151.5 |
| Commercial and Industrial | 628.4 | 323.1 |
| **Total Customer Usage (GW-hrs)** [3] | **933.0** | **474.6** |
| **Customer Usage (MMBTU)** | | |
| Residential | 7,214,000 | 1,552,000 |
| Commercial and Industrial | 5,666,000 | 988,000 |
| **Total Customer Usage (MMBTU)** [1,2,3] | **12,880,000** | **2,540,000** |

[1] New England Gas System was acquired on December 20, 2013

[2] Peach State Gas System was acquired on April 1, 2013.

[3] Granite State Electric System and EnergyNorth Gas System were acquired on July 3, 2012.

The Liberty Utilities (East) region is comprised of Liberty Utilities' operations in New Hampshire, Massachusetts and Georgia. The Liberty Utilities (East) region acquired its natural gas distribution system in Massachusetts on December 20, 2013, its natural gas distribution system in Georgia on April 1, 2013, and the New Hampshire natural gas and electric distribution systems on July 3, 2012; accordingly the twelve month results for 2012 are not comparative.

For the twelve months ended December 31, 2013, the Liberty Utilities (East) region's electricity usage totalled 933.0 GW-hrs and natural gas usage totalled 12,880,000 MMBTU. The Peach State Gas System usage totalled 3,369,000 MMBTU, while the New England Gas System usage totalled 242,000 MMBTU.

As a result of the acquisition of the New England Gas System and the Peach State Gas Systems, the Liberty Utilities (East) region added approximately 115,000 total natural gas connections.

| | Year ended December 31, 2013 U.S. $ (millions) | Year ended December 31, 2012 U.S. $ (millions) | Year ended December 31, 2013 Can $ (millions) | Year ended December 31, 2012 Can $ (millions) |
|---|---|---|---|---|
| Electricity Assets for regulatory purposes | **101.1** | 88.4 | | |
| Natural Gas for regulatory purposes | **513.4** | 263.4 | | |
| **Revenue** | | | | |
| Utility electricity sales and distribution[1] | **$ 85.7** | $ 36.8 | **$ 88.3** | $ 36.7 |
| Utility natural gas sales and distribution[2,3,4] | **164.1** | 45.7 | **169.1** | 45.3 |
| Gas Transportation | **13.4** | 4.6 | **13.7** | 4.6 |
| Other Revenue | **—** | 0.1 | **—** | 0.1 |
| | **$ 263.2** | $ 87.2 | **$ 271.1** | $ 86.7 |
| Less: | | | | |
| Cost of Sales – Electricity[1] | **(55.9)** | (24.4) | **(57.6)** | (24.3) |
| Cost of Sales – Natural Gas[2,3,4,5] | **(99.8)** | (24.0) | **(102.8)** | (23.8) |
| Net Utility Sales | **$ 107.5** | $ 38.8 | **$ 110.7** | $ 38.6 |
| **Expenses** | | | | |
| Operating expenses | **(65.3)** | (30.4) | **(67.3)** | (30.2) |
| Other Income | **1.4** | 0.4 | **1.5** | 0.5 |
| **Division operating profit** | **$ 43.6** | $ 8.8 | **$ 44.9** | $ 8.9 |

1 Represents Granite State Electric System revenue and electricity costs since July 3, 2012 acquisition date.

2 Represents New England Gas System revenue and gas costs since December 20, 2013 acquisition date.

3 Represents Peach State Gas System revenue and gas costs since April 1, 2013 acquisition date.

4 Represents EnergyNorth Gas System revenue and costs since July 3, 2012 acquisition date.

5 Natural Gas costs are shown net of U.S. $11.7 million regulatory authorized deferral related to an under recovery of actual gas costs.

## 2013 Annual Operating Results

The Liberty Utilities (East) region has investments in electricity assets for regulatory purposes of U.S. $101.1 million, and natural gas assets for regulatory purposes of U.S. $513.4 million as at December 31, 2013, as compared to U.S $88.4 million and U.S. $263.4 million, respectively, as at December 31, 2012. The increase in electricity assets is primarily a result of the construction of a new substation, substation asset upgrades, and the construction of a new supply line by the Granite State Electric System, while the increase in gas assets for regulatory purposes from December 31, 2013 is primarily a result of maintenance and installation of new pipelines at the EnergyNorth Gas System, and the acquisitions of the Peach State and the New England Gas Systems.

For the twelve months ended December 31, 2013, the Liberty Utilities (East) region's revenue totalled U.S. $263.2 million as compared to U.S. $87.2 million during the same period in 2012.

For the twelve months ended December 31, 2013, the Liberty Utilities (East) region's revenue from utility electricity sales totalled U.S. $85.7 million.

For the twelve months ended December 31, 2013, the Liberty Utilities (East) region's revenue from natural gas sales and distribution totalled U.S. $164.1 million, of which the EnergyNorth Gas System contributed U.S $126.0 million, the Peach State Gas System contributed U.S. $35.1 million, and the newly acquired New England Gas System contributed $3.0 million.

For the twelve months ended December 31, 2013, the Liberty Utilities (East) region's revenue from gas transportation sales totalled U.S. $13.4 million. For the twelve months ended December 31, 2013, the EnergyNorth Gas System contributed U.S. $11.6 million, the Peach State Gas System contributed U.S.$1.3 million, and the newly acquired New England Gas System contributed U.S. $0.5 million.

For the twelve months ended December 31, 2013, electricity purchases for the Liberty Utilities (East) region totalled U.S. $55.9 million, and natural gas purchases totalled U.S. $99.8 million.

The cost of electricity and natural gas is passed through to the Liberty Utilities (East) region's customers in the rates they are charged. As a result, the division compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the twelve months ended December 31, 2013, net utility sales totalled U.S. $107.5 million compared to U.S. $38.8 million during the same period in 2012, an increase of $68.7 million. The increase is due to the fact that the division is reporting a full year of results in 2013 compared to partial year results in the previous year and the impact of the interim annual rate increase approved by the NHPUC on June 27, 2013.

For the twelve months ended December 31, 2013, operating expenses, excluding electricity and natural gas purchases, totalled U.S. $65.3 million. For the twelve months ended December 31, 2013, other income for the Liberty Utilities (East) region totaled U.S. $1.4 million, and primarily consists of an equity allowance for funds utilized during construction and rental income. For the twelve months ended December 31, 2013, the Liberty Utilities (East) region's operating profit totalled U.S. $43.6 million.

Measured in Canadian dollars, the Liberty Utilities (East) region's operating profit was $44.9 million.

| | Three months ended December 31, | |
|---|---|---|
| | **2013** | **2012** |
| **Average Active Natural Gas Connections For The Period** | | |
| Residential | 178,900 | 73,300 |
| Commercial and Industrial | 17,100 | 8,700 |
| **Total Customer Usage (GW-hrs)** | **196,000** | **82,000** |
| | | |
| **Average Active Electric Connections For The Period** | | |
| Residential | 36,600 | 36,600 |
| Commercial and Industrial | 6,500 | 6,500 |
| **Total Average Active Electric Connections For The Period** | **43,100** | **43,100** |
| | | |
| **Customer Usage (GW-hrs)** | | |
| Residential | 69.4 | 68.5 |
| Commercial and Industrial | 145.3 | 143.6 |
| **Total Customer Usage (GW-hrs)** | **214.7** | **212.1** |
| | | |
| **Customer Usage (MMBTU)** | | |
| Residential | 2,068,000 | 1,199,000 |
| Commercial and Industrial | 2,147,000 | 745,000 |
| **Total Customer Usage (MMBTU)** | **4,215,000** | **1,944,000** |

For the three months ended December 31, 2013, the Liberty Utilities (East) region's electricity usage totalled 214.7 GW-hrs and natural gas usage totalled 4,215,000 MMBTU as compared to 212.1 GW-hrs and 1,944,000 MMBTU during the same period in 2012. The Peach State Gas System usage totalled 1,394,000 MMBTU, while the New England Gas System usage totalled 242,000 MMBTU.

| | Three months ended December 31, | | Three months ended December 31, | |
|---|---|---|---|---|
| | **2013 U.S. $ (millions)** | 2012 U.S. $ (millions) | **2013 Can $ (millions)** | 2012 Can $ (millions) |
| **Revenue** | | | | |
| Utility electricity sales and distribution | **$ 22.2** | $ 17.7 | **$ 23.3** | $ 17.6 |
| Utility natural gas sales and distribution[1,2] | **62.4** | 35.3 | **65.7** | 34.9 |
| Gas Transportation | **3.5** | 2.8 | **3.7** | 2.8 |
| **Other Revenue** | **—** | — | **—** | — |
| | **$ 88.1** | $ 55.8 | **$ 92.7** | $ 55.3 |
| Less: | | | | |
| Cost of Sales – Electricity | **(14.7)** | (12.3) | **(15.5)** | (12.2) |
| Cost of Sales – Natural Gas[1,2,3] | **(39.8)** | (21.9) | **(41.9)** | (21.7) |
| Net Utility Sales | **$ 33.6** | $ 21.6 | **$ 35.3** | $ 21.4 |
| **Expenses** | | | | |
| Operating expenses | **(18.2)** | (16.5) | **(19.1)** | (16.3) |
| Other income | **0.3** | 0.4 | **0.4** | 0.4 |
| **Division operating profit** | **$ 15.7** | $ 5.5 | **$ 16.6** | $ 5.5 |

1 Represents New England Gas System revenue and gas costs since December 20, 2013 acquisition date.

2 Represents Peach State Gas System revenue and gas costs since April 1, 2013 acquisition date.

3 Natural Gas costs are shown net of U.S. $2.5 million regulatory authorized deferral related to an under recovery of actual gas costs.

## 2013 Fourth Quarter Operating Results

For the three months ended December 31, 2013, the Liberty Utilities (East) region's revenue totalled U.S. $88.1 million, as compared to U.S. $55.8 million during the same period in 2012, an increase of U.S. $32.3 million, or 57.9%. The increase in revenue can be primarily attributed to the acquisition of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013.

For the three months ended December 31, 2013, the Liberty Utilities (East) region's revenue from utility electricity sales totalled U.S. $22.2 million as compared to U.S. $17.7 million during the same period in 2012, an increase of $4.5 million, or 25.4%, primarily due to interim rates in place at the Granite State Electric System effective July 1, 2013.

For the three months ended December 31, 2013, the Liberty Utilities (East) region's revenue from natural gas sales and distribution totalled U.S. $62.4 million as compared to U.S. $35.3 million during the same period in 2012, an increase of U.S. $27.1 million, or 76.8%. During the three months ended December 31, 2013, the EnergyNorth Gas System contributed U.S. $43.4 million, while the Peach State Gas System contributed U.S.$16.0 million, and the newly acquired the New England Gas System contributed U.S. $3.0 million.

For the three months ended December 31, 2013, the Liberty Utilities (East) region's revenue from gas transportation sales totalled U.S. $3.5 million as compared to U.S. $2.8 million during the same period in 2012, an increase of U.S. $0.7 million, or 25.0%. During the three months ended December 31, 2013 the EnergyNorth Gas System contributed U.S.$2.6 million, the Peach State Gas System contributed U.S. $0.4 million, and the newly acquired New England Gas System contributed U.S. $0.5 million.

For the three months ended December 31, 2013, electricity purchases for the Liberty Utilities (East) region totalled U.S. $14.7 million, and natural gas purchases totalled U.S. $39.8 million as compared to U.S. $12.3 million and U.S. $21.9 million, respectively, during the same period in 2012. The overall electricity purchase expense increase of U.S $2.4 million was primarily the result of an 18% increase in weighted average electricity rates as compared to the same period in 2013 and a 1% increase in the volume of electricity purchased to meet customer demand. The overall natural gas purchases increases can be primarily attributed to the acquisition of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013.

The cost of electricity and natural gas is passed through to the Liberty Utilities (East) region's customers. As a result, the division compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the three months ended December 31, 2013, net utility sales for the Liberty Utilities (East) region totalled U.S. $33.6 million as compared to U.S. $21.6 million during the same period in 2012, an increase of U.S.$12.0 million, or 55.6%, primarily due to an interim annual rate increase approved by the NHPUC on June 27, 2013 and higher customer counts, due to the acquisition of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013.

For the three months ended December 31, 2013, operating expenses, excluding electricity and natural gas purchases, totalled U.S. $18.2 million as compared to U.S. $16.5 million during the same period in 2012, an increase of U.S. $1.7 million, or 10.3%. The increase in operating expenses as compared to the same period in 2012 can be primarily attributed to the acquisition of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013.

For the three months ended December 31, 2013, other income for the Liberty Utilities (East) region totaled U.S. $0.3 million, and primarily consists of an equity allowance for funds utilized during construction and rental income.

For the three months ended December 31, 2013, the Liberty Utilities (East) region's operating profit totalled U.S. $15.7 million as compared to U.S. $5.5 million during the same period in 2012, an increase of U.S. $10.2 million. The increase in operating profit as compared to the same period in 2012 can be primarily attributed to the acquisition of the Peach State Gas System on April 1, 2013, and the New England Gas System on December 20, 2013.

Measured in Canadian dollars, the Liberty Utilities (East) region's operating profit was $16.6 million as compared to $5.5 million during the same period in 2012, an increase of $11.1 million.

## Regulatory Proceedings

The following table summarizes the major regulatory proceedings within Liberty utilities currently underway:

| Utility | State | Regulatory Proceeding Type | Rate Request (U.S. $000's) | Current Status |
|---|---|---|---|---|
| Rio Rico Water System | Arizona | General Rate Case | $750 | Order issued authorizing $420 annual increase |
| LPSCo Water System | Arizona | General Rate Case | $3,000 | Order expected first half of 2014 |
| Peach State Gas System | Georgia | Georgia Rate Adjustment Mechanism ("GRAM") filing | $4,900 | Settlement reached. Final Commission approval expected by the end of Q1 2014. |
| EnergyNorth Gas System | New Hampshire | Rate Proceeding | Cast iron/bare steel replacement program increase of $200 | Order approving $200 increase for one year |
| Granite State Electric System | New Hampshire | General Rate Case | $13,000 + $1,200 step adjustment in 2014 | Settlement reached for $10,200 + $1,100 in step increase for 2014. Commission approval expected by the end of Q1 2014 |
| Missouri Gas System | Missouri | General Rate Case | $6,300 | Order expected first quarter of 2015 |

On May 31, 2012, the Liberty Utilities (West) region filed a general rate case with the Arizona Corporation Commission ("ACC") related to the Rio Rico Water System. The filing sought, among other things, an increase in EBITDA by U.S. $0.8 million over 2011 results if approved as filed. On July 17, 2013, an order was received from the ACC which corresponds to an increase in EBITDA of approximately U.S. $0.4 million per year.

On February 28, 2013, LPSCo Water System filed a general rate case with the Arizona Corporation Commission related to the LPSCo Water System seeking, among other things, an increase in EBITDA by U.S. $3.0 million over the 2012 results if approved as filed. The application seeks recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application seeks an accelerated infrastructure recovery surcharge, a purchased power pass-through mechanism to recover power price increases between test years, a property tax accounting deferral to defer increases in property taxes between test years and a policy statement on rate design to begin the gradual shift of moving more revenue recovery to fixed charges versus commodity charges. New rates are expected to be implemented in the first half of 2014.

On October 30, 2013, the Peach State Gas System filed an application to increase rates by U.S. $4.9 million in its annual Georgia Revenue Adjustment Mechanism (“GRAM”) filing with the Georgia Public Service Commission (“GPSC”). In January 2014, Liberty Utilities and the Staff of the GPSC agreed to a settlement which will provide an annual revenue increase of U.S. $4.7 million. It is anticipated that this settlement will be approved in March 2014.

On May 15, 2013, the Liberty Utilities (East) region filed its required fiscal year 2013 (April 1, 2012 - March 31, 2013) cast iron/bare steel (CIBS) replacement program results for EnergyNorth Gas System with the NHPUC. As part of this filing, Liberty requested an annual increase in base distribution rates of U.S. $0.2 million effective July 1, 2013. On June 26, 2013, the NHPUC approved the increase.

On March 29, 2013, the Granite State Electric System filed a rate case with the NHPUC seeking an increase in rates of U.S. $13.0 million, and an additional U.S. $1.2 million increase in 2014 subject to the completion of certain capital projects. The filing is based on a 2012 test year, with revenues and expenses adjusted to reflect known and measurable changes. Among other things, the Granite State Electric System requested and received approval to continue the current cost-recovery tracking mechanism related to the Reliability Enhancement and Vegetation Management Plan and was granted an annual rate increase of U.S. $0.4 million starting July 1, 2013. The Granite State Electric System also requested a modification to allow for recovery of pre-staging personnel and equipment for qualifying storms. On June 27, 2013, the NHPUC approved a settlement agreement authorizing a temporary annual rate increase of U.S.$6.5 million effective July 1, 2013, and provides recognition for Liberty to request an increase to its storm recovery adjustment factor (“SRAF”). On January 22, 2014, the Granite State Electric System entered a settlement with the New Hampshire PUC Staff, which will provide for a rate increase of U.S.$10.9 million consisting of U.S. $9.8 million in base rates and an additional U.S. $1.1 million for incremental capital expended after the test year. In addition, the settlement allows for one time recovery of rate case expenses of U.S. $0.4 million. It is anticipated that the settlement will be approved in the first quarter of 2014.

On July 2, 2013, the Missouri Gas System filed an application with the Missouri Public Service Commission (“MPSC”) seeking accelerated recovery for infrastructure deployed under the utility’s infrastructure system replacement surcharge (“ISRS”). The filing was approved by MPSC on October 16th, 2013 which is expected to increase revenues and EBITDA by U.S. $0.6 million.

In the first quarter of 2014, the Midstates Gas System filed a rate case with the Missouri Public Service Commission ("MOPSC") seeking an increase in EBITDA of U.S. $6.3 million. The filing is based on a test year ending September 30, 2013, with revenues, expenses and rate bases adjusted to reflect known and measurable changes through April 30, 2014. The case is expected to conclude in first quarter of 2015.

## APUC: Corporate and Other Expenses

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2013 (millions)** | 2012 (millions) | **2013 (millions)** | **2012** (millions) |
| Corporate and other expenses: | | | | |
| Administrative expenses | **$ 5.2** | $ 5.3 | **$ 23.5** | $ 19.6 |
| (Gain)/Loss on foreign exchange | **(0.1)** | (1.6) | **(0.6)** | (0.6) |
| Interest expense | **14.4** | 11.1 | **53.3** | 35.6 |
| Interest, dividend and other Income | **0.7** | 0.4 | **2.5** | 2.1 |
| Write down of long lived assets | **—** | — | **—** | — |
| Acquisition-related costs | **0.6** | 1.3 | **2.1** | 7.7 |
| (Gain)/Loss on derivative financial instruments | **(2.7)** | (0.4) | **(5.2)** | (0.2) |
| Income tax expense/(recovery) | **5.2** | (6.5) | **9.2** | (14.4) |

### 2013 Annual Corporate and Other Expenses

During the year ended December 31, 2013, administrative expenses totalled $23.5 million, as compared to $19.6 million in the same period in 2012. The expense increase in the year ended December 31, 2013 primarily results from additional personnel, increased wages, additional costs required to administer APUC’s operations, share based compensation expense and other costs as compared to the same period in 2012.

For the year ended December 31, 2013, interest expense totalled $53.3 million as compared to $35.6 million in the same period in 2012. The increased interest expense is a result of new indebtedness incurred during the second half of 2012 and the first quarter of 2013 used to partially finance the new acquisitions and fund other growth initiatives. These amounts were partially offset by $4.9 million in reduced interest expense related to the Series 3 convertible debentures and $1.7 million in 2012 related to the Quebec water lease litigation.

For the year ended December 31, 2013, interest, dividend and other income totalled $2.5 million as compared to $2.1 million in the same period in 2012. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

For the year ended December 31, 2013, acquisition related costs totalled $2.1 million as compared to $7.7 million in the same period in 2012. Acquisition related costs will vary from period to period depending on the level of activity and complexity associated with various acquisitions.

For the year ended December 31, 2013, gains on derivative financial instruments totalled $5.2 million as compared to $0.2 million in the same period in 2012. The increase was primarily driven by derivative gains on the AES market hedges due to increased market prices during 2013 as compared to the same period in 2012.

An income tax expense of $9.2 million was recorded in the year ended December 31, 2013, as compared to a recovery of $14.4 million during the same period in 2012. The increase income tax expense for the year ended December 31, 2013 is primarily due to higher earnings in the U.S. resulting from the various U.S. acquisitions completed in 2012, deferred taxes on HLBV income, the recognition of deferred credits from the utilization of deferred income tax assets recognized at the time of the Unit Exchange Offer, non-taxable inter-corporate dividends, and other items permanently non-deductible for tax purposes.

## 2013 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2013, administrative expenses totalled $5.2 million, as compared to $5.3 million in the same period in 2012.

For the quarter ended December 31, 2013, interest expense totalled $14.4 million as compared to $11.1 million in the same period in 2012. The increased interest expense is a result of new indebtedness incurred during the first half of 2013 used to partially finance the new acquisitions and fund other growth initiatives. These amounts were partially offset by reduced interest expense related to convertible debentures due to the conversion of the Series 3 Debentures in the prior year.

For the quarter ended December 31, 2013, interest, dividend and other income totalled $0.7 million, as compared to $0.4 million in the same period in 2012. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

For the quarter ended December 31, 2013, gains on derivative financial instruments totalled $2.7 million, as compared to $0.4 million in the same period in 2012. The increase was primarily driven by derivative gains on the AES market hedges due to increased market prices during 2013 as compared to the same period in 2012.

An income tax expense of $5.2 million was recorded in the three months ended December 31, 2013, as compared to a recovery of $6.5 million during the same period in 2012. The income tax expense for the three months ended December 31, 2013 primarily due to deferred taxes on HLBV income, the recognition of deferred credits from the utilization of deferred income tax assets recognized at the time of the Unit Exchange Offer, non-taxable inter-corporate dividends, and other items permanently non-deductible for tax purposes.

# NON-GAAP PERFORMANCE MEASURES

## Reconciliation of Adjusted EBITDA to net earnings

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to GAAP consolidated net earnings.

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2013 (millions)** | 2012 (millions) | **2013 (millions)** | 2012 (millions) |
| Net earnings attributable to Shareholders | $ 13.1 | $ 6.4 | $ 20.3 | $ 14.5 |
| Add (deduct): | | | | |
| Net earnings / (loss) attributable to the non-controlling interest, exclusive of HLBV | **3.4** | (3.2) | **9.6** | (3.3) |
| (Earnings) / loss from discontinued operations | **6.7** | 0.4 | **42.0** | (1.0) |
| Income tax expense / (recovery) | **5.2** | (6.5) | **9.2** | (14.4) |
| Interest expense | **14.4** | 11.1 | **53.3** | 35.6 |
| Acquisition costs | **0.6** | 1.3 | **2.1** | 7.7 |
| Quebec water lease litigation | **—** | — | **—** | 0.5 |
| (Gain)/Loss on derivative financial instruments | **(2.7)** | (0.4) | **(5.2)** | (0.2) |
| (Gain)/Loss on foreign exchange | **(0.1)** | (1.6) | **(0.6)** | (0.6) |
| Depreciation and amortization | **27.0** | 16.5 | **96.2** | 49.3 |
| Adjusted EBITDA | **$ 67.6** | $ 24.0 | **$ 226.9** | $ 88.1 |

Hypothetical Liquidation at Book Value ("HLBV") represents the value of net tax attributes earned by APCo in the period from electricity generated by certain of its U.S. wind power generation facilities. The value of net tax attributes earned in the three and twelve months ended December 31, 2013 amounted to approximately $6.8 million and $20.4 million, respectively.

For the year ended December 31, 2013, Adjusted EBITDA totalled $226.9 million as compared to $88.1 million during the same period in 2012, an increase of $138.8 million. For the quarter ended December 31, 2013, Adjusted EBITDA totalled $67.6 million as compared to $24.0 million, an increase of $43.6 million compared to the same period in 2012.

The major factors impacting Adjusted EBITDA are set out below. A more detailed analysis of these factors is presented within the business unit analysis.

| | Three months ended December 31 (millions) | Year ended December 31 (millions) |
|---|---|---|
| Comparative Prior Period Adjusted EBITDA | $ 24.0 | $ 88.1 |
| Significant Changes: | | |
| Liberty Utilities: | | |
| Increased demand and rate decoupling at the CalPeco Electric System | 0.8 | 9.3 |
| Acquisitions | 12.8 | 48.5 |
| APCo: | | |
| Renewable | | |
| Increased hydrology resource | 0.8 | 6.6 |
| Acquisitions of the U.S. Wind Facilities | 23.6 | 62.9 |
| Sale of Renewable Energy Credits | 2.2 | 5.7 |
| Increased wind resources at the St Leon wind facilities | 1.0 | 1.3 |
| Increased demand for retail sales at AES | — | 2.6 |
| Thermal | | |
| Windsor Locks & Sanger Facilities - Increased energy sales | 0.3 | 2.5 |
| Administrative expense | 0.2 | (3.9) |
| Increased/(decreased) results from the stronger U.S. dollar | 4.3 | 5.0 |
| Other | (2.4) | (1.7) |
| Current Period Adjusted EBITDA | $ 67.6 | $ 226.9 |

## Reconciliation of adjusted net earnings to net earnings

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to adjusted net earnings and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with GAAP.

The following table shows the reconciliation of net earnings to adjusted net earnings exclusive of these items:

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2013 (millions)** | 2012 (millions) | **2013 (millions)** | 2012 (millions) |
| Net earnings attributable to Shareholders | **$ 13.1** | $ 6.4 | **$ 20.3** | $ 14.5 |
| Add (deduct): | | | | |
| (Gain) / Loss from discontinued operations, net of tax | **6.7** | 0.4 | **42.0** | (1.0) |
| (Gain)/Loss on derivative financial instruments, net of tax | **(1.6)** | (0.2) | **(2.7)** | (0.2) |
| Cross Currency Interest Rate Swap interest differential | **—** | — | **0.3** | — |
| Quebec water lease litigation and interest, net of tax | **—** | — | **—** | 1.2 |
| (Gain)/Loss on foreign exchange, net of tax | **(0.1)** | (0.9) | **(0.3)** | (0.3) |
| Acquisition costs, net of tax | **0.4** | 0.8 | **1.3** | 4.7 |
| Adjusted net earnings | **$ 18.5** | $ 6.5 | **$ 60.9** | $ 18.9 |
| Adjusted net earnings per share | **$ 0.08** | $ 0.03 | **$ 0.27** | $ 0.11 |

For the year ended December 31, 2013, adjusted net earnings totalled $60.9 million as compared to adjusted net earnings of $18.9 million, an increase of $42.0 million as compared to the same period in 2012. The increase in adjusted net earnings for the year ended December 31, 2013 is primarily due to higher income from operations, decreased acquisition costs partially offset by higher interest expense, and depreciation and amortization expense as compared to the same period in 2012.

For the three months ended December 31, 2013, adjusted net earnings totalled $18.5 million as compared to adjusted net earnings of $6.5 million, an increase of $12.0 million as compared to the same period in 2012. The increase in adjusted net earnings for the three months ended December 31, 2013 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense, and higher interest expense as compared to the same period in 2012.

## Reconciliation of adjusted funds from operations to cash flows from operating activities

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations and Statement of Cash Flows. This supplementary disclosure is intended to more fully explain disclosures related to adjusted funds from operations and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to funds from operations in accordance with GAAP.

The following table shows the reconciliation of funds from operations to adjusted funds from operations exclusive of these items:

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2013 (millions)** | 2012 (millions) | **2013 (millions)** | 2012 (millions) |
| Cash flows from operating activities | **$ 31.3** | $ 17.1 | **$ 98.9** | $ 63.0 |
| Add (deduct): | | | | |
| Changes in non-cash operating items | **13.5** | 7.2 | **47.8** | 3.9 |
| Cash (provided)/used in discontinued operation | **0.5** | (1.0) | **4.4** | (7.8) |
| Cross Currency Swap interest difference | **—** | — | **0.3** | — |
| Acquisition costs | **0.6** | 1.3 | **2.1** | 7.7 |
| Adjusted funds from operations | **$ 45.9** | $ 24.6 | **$ 153.5** | $ 66.8 |
| Adjusted funds from operations per share | **0.22** | **0.14** | **0.72** | 0.42 |

For the year ended December 31, 2013, adjusted funds from operations totalled $153.5 million as compared to adjusted funds from operations of $66.8 million, an increase of $86.7 million as compared to the same period in 2012.

For the three months ended December 31, 2013, adjusted funds from operations totalled $45.9 million as compared to adjusted funds from operations of $24.6 million, an increase of $21.3 million as compared to the same period in 2012.

## Summary of Property, Plant and Equipment Expenditures

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2013 (millions)** | 2012 (millions) | **2013 (millions)** | 2012 (millions) |
| **APCo:** | | | | |
| Renewable | **$ 18.0** | $ 7.5 | **$ 46.9** | $ 21.1 |
| Thermal | **1.3** | (2.0) | **2.6** | 10.3 |
| **Total APCo** | **$ 19.3** | $ 5.5 | **$ 49.5** | $ 31.4 |
| **LIBERTY UTILITIES** | | | | |
| West | **13.4** | 9.6 | **23.7** | 23.2 |
| Central | **8.4** | 8.8 | **28.6** | 10.8 |
| East | **21.6** | 8.9 | **56.6** | 12.5 |
| **Total Liberty Utilities** | **$ 43.4** | $ 27.3 | **$ 108.9** | $ 46.5 |
| Corporate | **—** | 0.1 | **—** | — |
| **Total** | **$ 62.7** | $ 32.9 | **$ 158.4** | $ 77.9 |

The company's consolidated capital expenditure plan for 2014 is approximately $460.0 million. APCo expects to invest approximately $260.0 million primarily in connection with the development of its existing project pipeline. Liberty Utilities expects to invest approximately $200.0 million primarily to improve the reliability and efficiency of its gas, and electric utility distribution systems.

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, bank credit facilities as well as the debt and equity capital markets to finance its property, plant and equipment expenditures and other commitments.

### 2013 Annual Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2013, APCo incurred capital expenditures of $49.5 million, as compared to $31.4 million during the comparable period in 2012,

During the twelve months ended December 31, 2013, APCo's Renewable Energy Division spent $46.9 million in capital expenditures as compared to $21.1 million in the comparable period in 2012. The capital expenditures primarily relate to project costs for the Cornwall Solar, Chaplin and St Damase development projects, as well as major repairs and upgrades at the Long Sault and Tinker Hydro Facilities. APCo's Thermal Energy Division net capital expenditures were $2.6 million, as compared to $10.3 million in the comparable period in 2012. The capital expenditures in the prior year were primarily related to the Windsor Locks repowering and the major maintenance at the Sanger Thermal Facility offset by two one-time, non-recurring items received by the Windsor Locks Thermal Facility: the $6.5 million grant from the State of Connecticut; and a $2.4 million heat and power ITC sponsored by the U.S. Federal Government.

During the twelve months ended December 31, 2013, Liberty Utilities invested $108.9 million in capital expenditures as compared to $46.5 million during the comparable period in 2012. The Liberty Utilities (West) region's $23.7 million investment in capital expenditures was primarily related to growth and upgrades at the CalPeco Electric System and the expansion of the LPSCo Water System. The Liberty Utility (Central) region's $28.6 million investment in capital expenditures was primarily related to pipe expansion and replacement activities, IT system implementations, and the construction of a new building, as a result of the Midstate Gas Systems acquisition. The Liberty Utility (East) region's $56.6 million investment in capital expenditures reflected the installation of a new substation, the start of a second supply line, the completion of certain substation upgrades and reliability enhancement projects on the Granite State Electric System, the installation of new mains and services supporting growth and distribution main replacements and reinforcements on the EnergyNorth Gas system, and system updates at the Peach State Gas System.

## 2013 Fourth Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2013, APCo incurred capital expenditures of $19.3 million, as compared to $5.5 million during the comparable period in 2012. During the three months ended December 31, 2013, APCo's Renewable Energy Division spent $18.0 million in capital expenditures as compared to $7.5 million in the comparable period in 2012. The capital expenditures primarily relate to Cornwall Solar and St. Damase development proejcts, as well as upgrades at the Tinker Hydro Facility. APCo's Thermal Energy Division net capital expenditures were $1.3 million, as compared to capital recovery of $2.0 million in the comparable period in 2012. The 2013 thermal capital expenditures consist of $1.0 relating to Windsor Locks Thermal Facility and $0.3 million relating to Sanger Thermal Facility whereas the prior capital expenditures were $0.4 million relating to Sanger Thermal Facility offset by a $2.4 million ITC sponsored by the U.S. Federal Government related to the repowering of the Windsor Locks Thermal Facility.

During the three months ended December 31, 2013, Liberty Utilities invested $43.4 million in capital expenditures as compared to $27.3 million during the comparable period in 2012. The Liberty Utilities (West) region's spend was primarily related to growth and upgrades at the CalPeco Electric System and the expansion of the LPSCo Water System. The Liberty Utility (Central) region's $8.4 million investment in capital expenditures was primarily related to pipe expansion and replacement activities and IT system implementations, as a result of the Midstates Gas System acquisition. The Liberty Utility (East) region's $21.6 million investment in capital expenditures was primarily related to a second supply line and reliability enhancement projects on the Granite State Electric System, the installation of new mains and services supporting growth and system reinforcements on the EnergyNorth Gas System, and system updates at the Peach State Gas System.

## Quebec Dam Safety Act

As a result of the dam safety legislation passed in Quebec (Bill C93), APCo has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. Out of these, nine assessments have been submitted to and accepted by the Quebec government. The assessments have identified possible remedial work at seven facilities. Of these seven, remediation work has now been completed at three facilities, monitoring activities and options analysis are being performed for two facilities, and remedial work is being planned at two facilities.

APCo currently estimates further capital expenditures of approximately $15.4 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

| | Total | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|
| Future Estimated Bill C-93 Capital Expenditures | 15.4 | 1.0 | 7.3 | 6.8 | 0.3 |

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre, and Rivière-du-Loup Hydro Facilities.

APCo completed the majority of the second phase of the on-site remediation work for the Mont Laurier Hydro Facility in 2013 at a capital cost of approximately $0.2 million. The on-site remediation is now substantially complete.

In 2013 APCo completed a risk review of the of the dam rehabilitation plan for the Donnacona Hydro Facility and will explore methods to reduce risk associated with the rehabilitation project in 2014 . The remedial on-site work is anticipated to start in 2015 and be completed in 2016.

The dam safety study and a detailed condition assessment for the St. Alban facility have been completed. A small portion of the on-site remediation associated with the spillway gate superstructure was performed in 2013 at a cost of $0.1 million. APCo anticipates engineering and regulatory review for the remediation of the main dam to be performed in 2014, with remedial work in 2015 to 2016.

APCo is presently reviewing options with respect to the Belleterre Hydro Facility including the removal of several small dams that are not required for power generation. APCo anticipates completion of any required work on these dams by 2017.

Engineering for the Riviere-du-Loup Hydro Facility was completed in 2012. Following a geotechnical investigation, the remediation work is now estimated at $1.1 million. Completion of the remedial work is anticipated in 2014 and 2015.

The dam remediation work related to the Rawdon and Chute Ford Hydro Facilities has been completed.

In addition to the C-93 related dam remediation work, APCo has implemented a dam condition monitoring program at some of the above facilities following recommendations specified in the dam safety reviews.

# Liquidity and Capital Reserves

APUC has revolving operating facilities available at APUC, APCo and Liberty Utilities to manage the liquidity and working capital requirements of each division (collectively the "Facilities").

## Bank Credit Facilities

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its subsidiaries as at December 31, 2013 under the Facilities:

| | As at December 31, 2013 | | | | As at Dec 31 2012 |
|---|---|---|---|---|---|
| | APUC (millions) | APCo (millions) | Liberty Utilities (millions) | Total (millions) | Total (millions) |
| Committed Facilities | $ 65.0 | $ 200.0 | $ 212.7 | **$ 477.7** | $ 329.5 |
| Funds drawn on Facilities | — | (124.6) | (85.6) | (210.2) | (54.5) |
| Letters of Credit issued | (9.9) | (47.7) | (7.3) | (64.9) | (50.7) |
| Funds available for draws on the Facilities | **$ 55.1** | **$ 27.7** | **$ 119.8** | **$ 202.6** | **$ 224.3** |
| Cash on Hand | | | | 13.8 | 53.1 |
| **Total liquidity and capital reserves** | | | | **$ 216.4** | **$ 277.4** |

As at December 31, 2013, the APUC Credit Facility, a $65.0 million senior unsecured revolving credit facility, was undrawn and had $9.9 million of outstanding letters of credit.

As at December 31, 2013, the APCo $200.0 million senior unsecured revolving credit facility (the "APCo Facility") had drawn $124.6 million and had $47.7 million in outstanding letters of credit under the APCo Facility.

As at December 31, 2013, the Liberty Utilities $212.7 million (U.S.$200.0 million) senior unsecured revolving credit facility (the "Liberty Facility") had drawn $85.6 million and had $7.3 million of outstanding letters of credit.

On November 19th, 2013, APUC amended its existing $30.0 million senior unsecured credit facility ("APUC Facility") to increase the commitments available to $65.0 million and extend maturity to November 19, 2016. On January 3rd, 2014 a subsidiary of APUC drew on the APUC Facility to acquire a 100% interest in an office building at an approximate cost of $46.8 million. The building will be approximately 50% occupied by APUC and serve as corporate headquarters with the remainder leased to third parties.

On September 30, 2013, Liberty Utilities increased the credit available under the senior unsecured revolving credit facility (the "Liberty Facility") to U.S. $200.0 million from U.S. $100.0 million. The larger credit facility provides Liberty Utilities with the additional liquidity required resulting from the various acquisitions completed in 2013 and on execution of near term organic growth opportunities. In addition to a larger credit facility, the tenor has been increased from three years to five years and several other terms under the facility, including pricing, have improved. The amended facility will now expire on September 30, 2018.

## Long Term Debt

On January 1, 2013, in conjunction with the acquisition of the Shady Oaks Wind Facility, APCo assumed a U.S. $150.0 million dollar variable rate long term credit facility. The facility is secured by the assets of the Shady Oaks Wind Facility. In 2013 APCo made principal payments of U.S. $25.0 million in the second quarter and U.S. $3.0 million in the third quarter of 2013 and will be required to make semi-annual principal payments ranging between U.S. $3.0 million and U.S. $6.0 million thereafter. The facility matures in 2026. Funds advanced against the facility are repayable at any time without penalty. Accordingly, subsequent to year end, APCo made a U.S.$ 40.0 million prepayment against the principal balance outstanding.

On March 14, 2013 Liberty Utilities completed a U.S. $15.0 million private placement debt financing. The notes are senior unsecured notes with a 10 year bullet maturity and carry a coupon of 4.14%.

On July 31, 2013, Liberty Utilities issued U.S. $125.0 million of debt through a private placement. The notes are senior unsecured with an average life maturity of approximately ten years and a weighted average coupon of 3.81%.

On December 20, 2013, in connection with the acquisition of New England Gas Company, Liberty Utilities assumed first mortgage bonds of U.S. $6.0 million, bearing an interest rate of 7.24%, maturing December 27, 2027; U.S. $7.0 million, bearing an interest rate of 7.99%, maturing December 26, 2026; and, U.S. $6.5 million, bearing an interest rate of 9.44%, maturing Feb 20, 2020.

Subsequent to year end, on January 17, 2104, APCo issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "APCo Debentures") pursuant to a private placement in Canada and the United States. The APCo Debentures were sold at a price of $99.864 per $100.00 principal amount resulting in an effective yield of 4.67%.

Concurrent with the offering, APCo entered into a fixed for fixed cross currency swap, coterminous with the APCo Debentures, to economically convert the Canadian dollar denominated debentures into U.S. dollars, resulting in an effective interest rate throughout the term of approximately 4.77%.

As at December 31, 2013 the weighted average tenor of APUC's total long term debt is approximately 8.4 years with an average interest rate of 4.8%

## Contractual Obligations

Information concerning contractual obligations as of December 31, 2013 is shown below:

| | Total (millions) | Due less than 1 year (millions) | Due 1 to 3 years (millions) | Due 4 to 5 years (millions) | Due after 5 years (millions) |
|---|---|---|---|---|---|
| Long-term debt obligations[1] | $ 1,255.6 | 8.3 | 147.1 | 171.9 | 928.3 |
| Advances in aid of construction | $ 78.9 | 1.2 | | | 77.7 |
| Interest on long-term debt obligations | $ 416.8 | 54.8 | 103.6 | 90.0 | 168.4 |
| Purchase obligations | $ 156.9 | 156.9 | | | |
| Environmental Obligations | $ 77.7 | 10.1 | 45.2 | 3.9 | 18.5 |
| Derivative financial instruments: | | | | | |
| Cross Currency Swap | $ 7.9 | — | — | — | 7.9 |
| Interest rate swap | $ 3.1 | 1.9 | 1.2 | — | — |
| Energy derivative contracts | $ 4.8 | 0.2 | 0.1 | — | 4.5 |
| Capital lease obligations | $ 4.0 | 0.1 | 3.9 | — | — |
| Capital projects | $ 51.6 | 49.3 | 2.3 | — | — |
| Long term service agreements | $ 633.2 | 24.1 | 53.3 | 57.5 | 498.3 |
| Purchased power | $ 111.5 | 64.6 | 46.9 | — | — |
| Gas delivery, service and supply agreements | $ 156.1 | 42.1 | 40.2 | 19.3 | 54.5 |
| Operating leases | $ 106.1 | 5.1 | 8.5 | 7.3 | 85.2 |
| Other obligations | $ 21.1 | 7.3 | — | — | 13.8 |
| Total obligations | $ 3,085.3 | $ 426.0 | $ 452.3 | $ 349.9 | $ 1,857.1 |

## Equity

The shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at December 31, 2013, APUC had 206,348,985 issued and outstanding common shares.

APUC may issue an unlimited number of common shares. The holders of common shares are entitled to dividends, if and when declared; to one vote for each share at meetings of the holders of common shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2013, APUC had issued 4,800,000 cumulative rate reset preferred shares, Series A (the "Series A Shares"), yielding 4.5% annually for the initial six-year period ending on December 31, 2018, and 100 Series C preferred shares (the "Series C Shares") that were issued in exchange for 100 Class B limited partnership units issued by St. Leon Wind Energy LP.

APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered holders of shares ("Shareholders") of APUC. As at December 31, 2013, 43.2 million common shares representing approximately 21% of total shares outstanding had been registered with the Reinvestment Plan and 2,126,258 shares had been issued during the year ended December 31, 2013. During the quarter ended December 31, 2013 688,886 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on January 15, 2014, an additional 501,818 common shares were issued under the Reinvestment Plan.

Subsequent to the end of the year, on March 5, 2014, APUC issued 4.0 million cumulative rate reset preferred shares, Series D at a price of $25 per share, for aggregate gross proceeds of $100 million. The shares yield 5.0% annually for the initial five-year period ending on March 31, 2019. The preferred shares have been assigned a rating of P-3 high and Pfd-3(low) by S&P and DBRS respectively. The proceeds of the offering were used to partially finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's credit facilities and for general corporate purposes.

On January 1, 2013, the Company issued 100 redeemable Series C Shares and exchanged such shares for the 100 Class B units that provide dividends identical to what is expected from the Class B units, as determined by independent consultants retained by the Independent Board Committee.

On November 19, 2012, APUC announced its intent to redeem, on January 1, 2013, the convertible unsecured debentures maturing on June 30, 2017 ("Series 3 Debentures") bearing interest at 7.0% per annum. During the year ended December 31, 2012, a principal amount of $61.6 million Series 3 Debentures were converted into 14,669,266 shares of APUC. The Series 3 Debentures were convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share. On December 31, 2012, there was a face value of $0.96 million Series 3 Debentures outstanding. Subsequent to the end of the quarter, on January 1, 2013, APUC redeemed the outstanding Series 3 Debentures and issued 150,816 shares as a result of the redemption. Following the redemption, there were no Series 3 Debentures outstanding.

## Emera subscription receipts

For the year ended December 31, 2013, a total of 15.2 million common shares were issued to Emera for proceeds of $90.5 million pursuant to subscription agreements in contemplation of certain previously announced transactions, as outlined below:

- On February 7, 2013 and February 14, 2013, respectively, in connection with the closing of the acquisition of the Minonk and Senate Wind Facilities from Gamesa USA that occurred on December 10, 2012, APUC issued 2.6 million common shares at a price of $5.74 and 5.2 million shares at a price of $5.74. The total $45 million in cash proceeds from the exercise of the subscription receipts were used to fund a portion of the cost of the acquisition;
- On February 14, 2013, in connection with the acquisition of Emera's non-controlling interest in the CalPeco Electric System, APUC issued 3.4 million common shares at a price of $4.72 for share proceeds of $16.1 million; and
- On March 26, 2013, in connection with the acquisition of the Peach State Gas System, APUC issued 4.0 million shares at a price of $7.40 per share to Emera pursuant to a subscription agreement, for total cash proceeds of $29.3 million. The cash proceeds were used to partially fund the acquisition of the Peach State Gas System.

As at March 6, 2014, in total, Emera owns 50.1 million APUC common shares representing approximately 24.2% of the total outstanding common shares of the Company, and there are no subscription receipts currently held by Emera. APUC believes issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

# SHARE BASED COMPENSATION PLANS

For the three and twelve months ended December 31, 2013, APUC recorded $570 and $2.0 million (2012 - $287 and $1.8 million) in total share-based compensation expense. No tax deduction was realized in the current year. The compensation expense is recorded as part of administrative expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2013, total unrecognized compensation costs related to non-vested options and share unit awards were $1.8 million and $0.1 million respectively, and are expected to be recognized over a period of 1.57 years and 1.0 year respectively.

### *Stock Option Plan*

APUC has a stock option plan that permits the grant of share options to key officers, directors, employees and selected service providers. Except in certain circumstances, the term of an Option shall not exceed ten (10) years from the date of the grant of the Option.

For the year ended December 31, 2013, 816,402 options were granted to senior executives and certain senior management of APUC which allow for the purchase of common shares at a weighted average price of $7.72. One third of the options will vest on each of January 1, 2014, 2015, and 2016.

As at December 31, 2013, APUC had 4,567,129 options issued and outstanding. APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date.

### *Performance Share Units*

APUC issues performance share units ("PSUs") to certain members of management other than senior executives as part of APUC's long-term incentive program. The PSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle these instruments in cash, these PSUs are accounted for as equity awards.

As at December 31, 2013, a total of 66,195 PSU's have been granted and outstanding under the PSU plan.

### *Directors Deferred Share Units*

APUC has a Deferred Share Unit Plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("DSUs") in lieu of cash compensation. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSU's in cash, these DSUs are accounted for as equity awards.

As at December 31, 2013, a total of 74,786 DSUs had been granted under the DSU plan.

### *Employee Share Purchase Plan*

APUC has an employee share purchase plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. As at December 31, 2013, a total of 146,813 shares had been issued under the ESPP.

# MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt levels, at APCo, Liberty Utilities and an overall company level, and its equity balances.

APUC's objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders; and
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

# RELATED PARTY TRANSACTIONS

## Resolution of Business Associations with APMI, Affiliates and Senior Executives

Ian Robertson and Chris Jarratt ("Senior Executives") are indirect shareholders of Algonquin Power Management Inc. ("APMI"), the former manager of the Company and several related affiliates (collectively the "Parties"). Prior to 2010, there were several related party transactions and co-owned assets which existed pursuant to the external management structure before the internalization of management which occurred on December 21, 2009.

In 2011, the Board formed an independent committee ("Independent Board Committee") and initiated a process to review all of the remaining business associations with the Parties in order to reduce and/or eliminate these relationships. The "Independent Board Committee" within this section refers to a Committee comprising the independent members of the Board of Directors of APUC as defined in National Instrument 58-101. The Independent Board Committee engaged independent consultants and advisors to assist with this process and to provide advice in respect thereof. Specifically, the independent advisors provided advice to the Independent Board Committee in relation to fair market valuations of the generating assets, tax and legal matters.

The process initiated in 2011 has been completed and all related party transactions between APUC and the Parties have been resolved to the satisfaction of the Independent Board Committee and the Board as discussed below.

The following describes the business associations and resolution with APMI and Senior Executives:

### *Due to and from related parties*

As at December 31, 2013, amounts due from related parties were nil (December 31, 2012 - $816) owed to APUC from the Parties and amounts due to related parties were nil (December 31, 2012 - $1,811) owed to the Parties.

Prior to 2010, APMI was the manager of APIF (predecessor organization to APUC) and at the time of the internalization of management, had a number of fees under negotiation as described below:

- APMI was one of the original developers of the Red Lily I Wind Facility and was entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of the Red Lily I Wind Facility. In 2011, APUC acquired APMI's interest in this royalty.
- As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee.
- During 2007, APUC allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee for which APMI was entitled to a portion thereof.
- During 2008, APMI provided construction supervision services for the construction of BCI Thermal Facility and was entitled to a construction supervision fee on the BCI projects.
- During 2009, APMI provided management services to APUC for which fees were earned but not paid. In the provision of these management services, APMI incurred and was also entitled to reimbursement of reasonable expenses in 2009 which were not reimbursed by APUC.

***Resolution***: The Independent Board Committee and the Parties entered into a definitive agreement on November 15, 2013 whereby APUC agree to pay the Parties $1,829 in connection with outstanding fees and the Parties shall pay APUC $812 in connection with reimbursement of expenses both in full satisfaction of the related party balances. The balances have been fully settled as at December 31, 2013.

The aforementioned transaction was completed by December 31, 2013.

### *Equity interests in Rattle Brook Hydro, Long Sault Hydro, and BCI Thermal Facilities*

Prior to December 31, 2013, the Parties owned interests in three power generation facilities in which APUC also has an interest in. A brief description of the facilities is provided as follows:

- Rattle Brook Hydro Facility is a 4 MW hydroelectric generating facility constructed in 1998 in which APUC owned a 45% interest and Senior Executives held an equity interest in the remaining 55%.
- Long Sault Hydro Facility is an 18MW hydroelectric generating facility constructed in 1997. APUC acquired its interest in the Long Sault Hydro Facility by way of subscribing to two notes from the original partners. One of the original partners is an affiliate of APMI which was entitled to receive 5% of the equity cash flows commencing in 2014.
- BCI is an energy supply facility which sells steam produced from APCo's EFW Facility . In 2004, APMI acquired 50 Class B partnership units in BCI equal to 50% of the annual returns on the project greater than 15%.

***Resolution***: As part of the process to resolve the co-ownership issue of the above noted assets, the Independent Board Committee undertook valuations by independent consultants which were reviewed and accepted by the Independent Board Committee. APUC and the Parties entered into an agreement whereby APUC would acquire the Parties' shares of Algonquin Power Corporation Inc. which owns a residual equity interest in the 18MW Long Sault Rapids Hydro Facility and the partnership interest in the BCI Thermal Facility for an amount equal to $3,780. In addition APUC and the Parties entered into an agreement whereby the Parties would acquire APUC's 45% interest in the 4MW Rattle Brook Hydro Facility for an amount equal to $3,408. APUC earned a fee of $400 from APC during the year ended December 31, 2013 (2012 -$nil) related to settlement of the related party transactions.

The aforementioned transaction was completed on December 31, 2013.

### *St Leon LP Units*

Third party investors, including Senior Executives previously held 100 Class B limited partnership units issued by the St. Leon Limited Partnership which is the legal owner of the St. Leon Wind Facility. The Class B units held by Senior Executives received cash distributions of $nil and $14 for the three and twelve months ended December 31, 2013 (2012 - $47 and $175).

***Resolution:*** On January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the 100 Class B units including 36 units held indirectly by Senior Management. The Series C preferred shares provide dividends identical to what is expected from the Class B units, as determined by independent consultants retained by the Independent Board Committee. Independent tax, legal and accounting advisors were also retained by the Independent Board Committee to provide advice in relation to the exchange.

As of January 1, 2013, no Senior Executives had any further direct or indirect ownership of the St. Leon facility.

### *Office Facilities*

APUC has leased a portion of its head office facilities since 2001 on a triple net basis from an entity partially owned by Senior Executives. The Independent Board Committee conducted independent reviews of the office leasing market and believes the current terms and conditions for office lease are at fair market value for a building of comparable size and quality. Base lease costs for the three and twelve months ended December 31, 2013 were $77 and $310 (2012 - $83 and $333).

***Resolution:*** The current office lease for a portion of its head office facilities expires on December 31, 2015. In August 2013, APUC through a wholly owned subsidiary has acquired a new office facility which is suitable for meeting the future head office needs of APUC. Upon occupancy of the new head office facilities which is anticipated to occur in 2014, it is expected that the currently occupied premises will be subleased to third parties and the relationship between APUC and Senior Executives in respect of office premises will be concluded.

The Board has deemed this related party transaction to have been satisfactorily addressed.

### *Chartered Aircraft*

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into an agreement to charter aircraft in which the Senior Executives have a partial ownership interest. In 2004, APUC remitted $1,300 to an affiliate of APMI as an advance against expense reimbursements (including utilization reserves) for APUC's business use of the aircraft. By the end of 2012 the entire advance had been amortized against expense reimbursements and therefore no amortization expense during the three and twelve months ended December 31, 2013 related to the advance were incurred (2012 - $52 and $279). During the three and twelve months ended December 31, 2013, APUC reimbursed direct costs in connection with the use of the aircraft of $161 and $472 (2012 - $103 and $598).

***Resolution:*** As of December 31, 2013, the remaining amount of the advance was $nil (December 31, 2012 - $nil) and as a result the Independent Board Committee is satisfied that the advance arrangement has concluded. The Independent Board Committee and the Parties have agreed that all future utilization of chartered aircraft will be undertaken through third party charter operators at fair market value and under arrangements in which the Senior Executives have no interest.

The Board has deemed this related party transaction to have been satisfactorily addressed.

### *Operations Services*

APUC provides supervisory services on a cost recovery basis for one small hydro facility hydroelectric generating facility where Senior Executives hold an equity interest. The fees paid in relation to the supervisory management services were nominal for the three and twelve months ended December 31, 2012 and 2013.

***Resolution***: This agreement terminated on December 31, 2013.

### *Trafalgar*

APCo owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar Hydro Facility"). In 1997, Trafalgar went into default under its debt obligations and an affiliate of APMI moved to foreclose on the assets. Subsequently Trafalgar went into bankruptcy. APUC and the affiliate of APMI have been jointly involved in litigation and in bankruptcy proceedings with Trafalgar since 2004. APMI initially funded $2 million in legal fees prior to 2004.

***Resolution:*** In 2004, the Board reimbursed APMI $1 million of the total third party legal fees (which to that point totalled $2 million), and APUC would fund future legal fees, third party costs and other liabilities. It was agreed that any net proceeds from the lawsuits would be shared proportionally to the quantum of net costs funded by each party.

The Board has deemed this related party transaction to have been satisfactorily addressed.

## Other Related Party Transactions

Related Party Transactions between APUC and Emera are discussed in the section below titled *"Transactions with Emera"*.

### *Transactions with Emera*

A member of the Board of Directors of APUC, Chris Huskilson, is an executive at Emera.

In 2011, a subsidiary of Emera provided lead market participant services for fuel capacity and forward reserve markets to ISO NE for the Windsor Locks facility. During the three and twelve months ended December 31, 2013 APUC paid U.S. $nil (2012 - U.S. $nil) in relation to this contract. In 2011, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.

For the three and twelve months ended December 31, 2013, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $1,453 and U.S. $6,042 (2012 - U.S. $1,539 and U.S. $6,096). In 2011, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S. $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

### *Other*

An individual related to Ian Robertson, CEO of APUC provided market research consulting services to certain subsidiaries of Liberty Utilities. During the three and twelve months ended December 31, 2013 APUC paid $nil and $29 (2012 - $nil and $nil) in relation to these services.

# TREASURY RISK MANAGEMENT

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. APUC ensures that both APCo and Liberty Utilities maintain insurance on all of their facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies including currency and interest rate hedging policies to manage its risk exposures.

There are a number of monetary and financial risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the U.S. versus Canadian dollar exchange rates, energy market prices, interest rate, liquidity and commodity price risk considerations, and credit risk associated with a reliance on key customers. The risks discussed below are not intended as a complete list of all exposures that APUC may encounter. A further assessment of APUC and its subsidiaries' business risks is also set out in the most recent AIF.

### *Foreign currency risk*

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 72% of EBITDA in 2013 and 70% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $16.2 million ($0.08 per share) on an annual basis.

APUC manages this risk primarily through the use of natural hedges by using U.S. long term debt to finance its U.S. operations. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes.

*Market price risk*

Liberty Utilities is not exposed to market price risk as rates charged to customers are stipulated by the respective regulatory bodies.

On May 15, 2012, APCo entered into a financial hedge, which expires December 31, 2016 with respect to its Dickson Dam Hydro Facility located in the Western region. The financial hedge is structured to hedge 75% of APCo's production volume against exposure to the Alberta Power Pool's current spot market rates. For the unhedged portion of production, each $10.00 per MW-hr change in the market prices in the Western region would result in a change in revenue of $0.2 million on an annualized basis.

The July 1, 2012 acquisition of Sandy Ridge Wind Facility included a financial hedge which commenced on January 1, 2013 for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility's production volume against exposure to PJM Western Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in the market prices would result in a change in revenue of about $0.3 million for the year.

The December 10, 2012 acquisition of Senate Wind Facility included a physical hedge which commenced on January 1, 2013 for a 15 year period. The physical hedge is structured to hedge 64% of Senate Wind Facility's production volume against exposure to ERCOT North Zone current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in the market prices would result in a change in revenue of about $1.1 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge which commenced on January 1, 2013 for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's production volume against exposure to PJM Northern Illinois Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in market prices would result in a change in revenue of about $1.1 million for the year.

For the Sandy Ridge, Senate and Minonk Wind Facilities, in the fourth quarter of 2013 APCo entered into unit contingent financial hedges which commenced January 1, 2014 for a one year period. These hedges are structured to hedge all of the production from the Facilities in excess of the production covered by the hedges described in the three preceding paragraphs. The hedges do not have a minimum volume commitment and hence the facilities do not bear any market risk associated with production. As a result, the Sandy Ridge, Senate and Minonk Wind Facilities now have hedges in place covering 100% of the energy produced.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract which commenced on January 1, 2013 for a 20 year period. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in market prices would result in a change in revenue of about $1.1 million for the year.

### *Credit/Counterparty risk*

APUC and its subsidiaries are subject to credit risk through its trade receivables, derivative financial instruments and short term investments. APUC has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

APUC does not believe this risk to be significant as approximately 85% of APCo Renewable Energy division's revenue, approximately 100% of APCo Thermal Energy division's revenue, and over 88.1% of APCo's total revenue is earned from large utility customers having a credit rating of BBB or better.The following chart sets out APCo's significant customers, their credit ratings and percentage of total revenue associated with the customer:

| Counterparty | Credit Rating [1] | Approximate Annual Revenues | Percent of Divisional Revenue |
|---|---|---|---|
| **Renewable Energy Division** | | | |
| PJM Interconnection LLC | Aa3 | 33.6 | 23.1% |
| Manitoba Hydro | Aa1 | 27.8 | 19.1% |
| Hydro Quebec | Aa2 | 22.4 | 15.4% |
| US Wind Hedge Counterparty[2] | A | 12.1 | 8.3% |
| Ontario Electricity Financial Corporation | Aa2 | 11.7 | 8.0% |
| Main Public Service[3] | BBB+ | 9.4 | 6.4% |
| Commonwealth Edison | BBB | 7.3 | 5.0% |
| **Total – Renewable** | | **$ 124.3** | **85.3%** |
| **Thermal Energy Division** | | | |
| Pacific Gas and Electric Company | A3 | 16.9 | 48.9% |
| Connecticut Light and Power | A- | 17.6 | 51.1% |
| **Total – Thermal** | | **$ 34.5** | **100.0%** |
| **Total – APCo** | | **$ 158.8** | **88.1%** |

1 Ratings by Moody's or Standard & Poor's as of February 2014.

2 Hedge counterparty for the Sandy Ridge, Senate, and Minonk Wind Facilities

3 Maine Public Service is a subsidiary of Emera.

The remaining revenue is primarily earned by Liberty Utilities. In this regard, the credit risk related to the Liberty Utilities (West) and Liberty Utilities (Central) regions' accounts receivable balances related to the water and wastewater utilities total U.S. $3.3 million which is spread over approximately 93,000 connections, resulting in an average outstanding balance of approximately $35.00 dollars per connection. Liberty Utilities (East) and Liberty Utilities (Central) regions' accounts receivable balances related to the natural gas utilities total U.S. $52.6 million, while the Liberty Utilities (East) and Liberty Utilities (West) regions' accounts receivable balances related to the electric utilities total U.S. 15.7 million. The natural gas and electrical utilities derive over 88% of their revenue from residential customers.

In addition to the counterparty risk related to customer sales outlined above, APCo and Liberty Utilities utilizes derivative instruments as hedges of certain financial risks as discussed elsewhere in this MD&A. APUC is exposed to credit risk related to counterparties to the extent those derivative instruments are in an asset position at a point in time. The company manages counterparty risk by entering into these instruments with counterparties having a credit rating of BBB- or better.

### *Interest rate risk*

The majority of debt outstanding in APUC and its subsidiaries is subject to a fixed rate of interest and as such is not subject to interest rate risk. Borrowings subject to variable interest rates are as follows:

- The APUC Facility is subject to a variable interest rate. The APUC Facility has no amounts outstanding as at December 31, 2013. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- The APCo Facility had $124.6 million outstanding as at December 31, 2013. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.2 million annually.
- APCo's project debt at its Sanger Thermal Facility has a balance of U.S. $19.2 million as at December 31, 2013. Assuming the current level of borrowings over an annual basis, a 100 basis point change in the variable rate charged would impact interest expense by U.S. $0.2 million annually.
- The Liberty Facility had $80.5 million outstanding as at December 31, 2013. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.8 million annually.
- The Shady Oaks Senior Debt Facility had $129.8 million outstanding as at December 31, 2013. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.3 million annually.

APUC does not actively manage interest rate risk on its variable interest rate borrowings due to the primarily short term and revolving nature of the amounts drawn.

### *Liquidity risk*

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due.

Both APCo and Liberty have established financing platforms to access new liquidity from the capital markets as requirements arise. APUC continually monitors the maturity profile of its debt and adjusts accordingly to ensure sufficient liquidity exists at each of APCo and Liberty Utilities to meet their liabilities when due.

As at December 31, 2013, APUC and its subsidiaries had a combined $202.6 million of committed and available credit facilities remaining and $13.8 million of cash resulting in $216.4 million of total liquidity and capital reserves.

APUC currently pays a dividend of $0.34 per common share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements and to fund working capital that, in its judgment, ensures APUC's long-term success. Based on the level of dividends paid during the year ended December 31, 2013, cash provided by operating activities exceeded dividends declared by 1.4 times and exceeds Adjusted Cash From Operations by 2.2 times.

The long term portion of debt totals approximately $1,255.6 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facilities and project debt with borrowings having less favorable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted.

The cash flow generated from several of APUC's operating facilities is subordinated to senior project debt. In the event that there was a breach of covenants or obligations with regard to any of these particular loans which was not remedied, the loan could go into default which could result in the lender realizing on its security and APUC losing its investment in such operating facility. APUC actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

***Commodity price risk***

APCo's exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty Utilities is exposed to energy price risk in the Liberty Utilities (West) and Liberty Utilities (East) regions. Additionally, Liberty Utilities is exposed to natural gas price risk in the Liberty Utilities (Central) and Liberty Utilities (East) regions.

In this regard, a discussion of this risk is set out as follows:

- APCo's Sanger Thermal Facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in an increase in net revenue by approximately $0.2 million on an annual basis.
- APCo's Windsor Locks Thermal Facility's ESA includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to Ahlstrom. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 million on an annual basis.
- AES provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 200,000 MW-hrs in fiscal 2014. While the Tinker facility is expected to provide the majority of the energy required to service these customers, AES anticipates having to purchase approximately 90,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy. The risk associated with the expected market purchases of 90,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 65,000 MWhrs of AES's anticipated purchases over the next 12 months at an average rate of approximately $59 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.3 million on an annualized basis.

Liberty Utilities is exposed to energy price risk in the Liberty Utilities (West) region which is mitigated through a regulatory balancing account. The Liberty Utilities (West) region provides electric service to the Lake Tahoe California basin and surrounding areas at rates approved by the CPUC. The CalPeco Electric System purchases the energy, capacity, and related service requirements for its customers from NV Energy via a purchase power agreement at rates reflecting NV Energy's system average costs.

The CalPeco Electric System's tariffs allow for the pass-through of energy costs to its rate payers on a dollar for dollar basis, through the energy cost adjustment clause ("ECAC") mechanism, which allows for the recovery or refund of changes in energy costs that are caused by the fluctuations in the price of fuel and purchased power. On a monthly basis, energy costs are compared to the CPUC approved base tariff energy rates and the difference is deferred to a balancing account. Annually, based on the balance of the ECAC balancing account, if the ECAC revenues were to increase or decrease by more than 5%, the CalPeco Electric System's ECAC tariff allows for a potential adjustment to the ECAC rates which would eliminate the risk associated with the fluctuating cost of fuel and purchased power. In the CalPeco Electric System's 2012 general rate case, a revenue decoupling mechanism and a vegetation management memorandum account were agreed upon. The revenue decoupling mechanism decouples base revenues from fluctuations caused by weather and economic factors reducing volumetric risk for the utility. The vegetation management memorandum account allows for the tracking and pass through of vegetation management expenses, one of the largest expenses of the utility, reducing the potential for expenses to exceed the amounts allowed for in general rates.

In the Liberty Utilities (East) region, the Granite State Electric System is an open access electric utility allowing for its customers to procure commodity services from competitive energy suppliers. For those customers that do not choose their own competitive energy supplier, the Granite State Electric System provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for all customers and quarterly for large customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of the Granite State Electric System's Default Service customers. Since this is a full requirements service, the winning bidder(s) take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

In the Liberty Utilities (East) region, the EnergyNorth Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties. The EnergyNorth Gas System's portfolio of assets, planning and forecasting methodology is approved by the NHPUC bi-annually through an Integrated Resource Plan filing. In addition, the EnergyNorth Gas System files with the NHPUC for recovery of its transportation and commodity costs through a semi-annual winter and summer Cost of Gas (COG) filing and approval process. The EnergyNorth Gas System establishes rates for its customers within the COG filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the EnergyNorth Gas System has implemented a NHPUC approved commodity hedging program designed to hedge approximately 60% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be pass-through to customers through the COG filing and the approved rates in said filing. Should commodity prices increase or decrease relative to the initial semi-annual COG rate filing, the EnergyNorth Gas System has the right to automatically adjust its rates going forward in order to minimize any under or over collection of its gas costs. In addition, any under collections may be carried forward with carrying costs to the next year's period COG filing, i.e. winter to winter and summer to summer.

The Liberty Utilities (Central) region purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual State Commissions for recovery of its transportation and commodity costs through an annual Purchase Gas Adjustment ("PGA") filing and approval process. The Liberty Utilities (Central) region establishes rates for its customers within the PGA filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the Liberty Utilities (Central) region has implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be pass-through to customers through the PGA filing and are embedded in the approved rates in said filing. The Liberty Utilities (Central) region may adjust its rates on a monthly or quarterly basis in order to account for any commodity price increase or decrease relative to the initial PGA rate, minimizing any under or over collection of its gas costs.

## OPERATIONAL RISK MANAGEMENT

APUC attempts to proactively manage its risk exposures in a prudent manner and has initiated a number of programs and policies such as employee health and safety programs and environmental safety programs to manage its risk exposures.

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the dependence upon APUC businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. A further assessment of APUC's business risks is set out in the most recent AIF.

### *Mechanical and Operational Risks*

APUC is entirely dependent upon the operations and assets of APUC's businesses. This profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards.

The hydro assets of APCo utilize dams to pond water for generation and if the dams burst catastrophic amounts of water would flood downriver from the facility. The units can be subjected to drought conditions and lose the ability to generate during peak load conditions, causing the facilities to miss on either hedged or PPA committed production levels. The risks of the Hydro facilities are mitigated by regular dam inspections and a maintenance program of the facility to lessen the risk of dam failure.

The wind assets of APCo could catch on fire, and depending on the season could ignite significant amounts of forest or crop downwind from the unit. The wind units could also be affected by large atmospheric conditions (e.g. El Nina) which will lower wind levels below our PPA and hedge minimum production levels. The wind units risk is mitigated by properly maintaining the units using long term maintenance agreements with the turbine O&M's by regular inspections and maintenance of property and liability insurance policies. Icing can be mitigated by shutting down the unit as icing is detected at the site.

The Thermal Energy Division uses natural gas and oil, and produce exhaust gases, which if not properly treated and monitored could cause hazardous chemicals to be released into the atmosphere. The units could also be restricted from purchasing gas/oil due to either shortages or pollution levels, which could hamper output of the facility. The mechanical and operational risks at the Thermal Energy Division are mitigated by the regular maintenance of the boiler system, and by continual monitoring of exhaust gases. Fuel restrictions can be hedged somewhat by long term purchases.

The water distribution networks of Liberty Utilities operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property.

The electricity distribution systems owned by Liberty Utilities are subject to storm events, usually winter storm events, whereby power lines can be brought down with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

The gas distribution systems owned by Liberty Utilities are subject to risks which may lead to fire and/or explosion which may impact life and property. Risks include third party damage, compromised system integrity, type/age of pipelines and severe weather events.

These risks are mitigated through the diversification of APUC's operations, both operationally (APCo and Liberty Utilities) and geographically (Canada and U.S.), the use of regular maintenance programs, including pipeline safety programs and compliance programs, and maintaining adequate insurance and the establishment of reserves for expenses.

### *Regulatory Risk*

Profitability of APUC businesses is in part dependent on regulatory climates in the jurisdictions in which it operates. In the case of some APCo hydroelectric facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue.

Liberty Utilities' facilities are subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. The Liberty Utilities (West) region's CalPeco Electric System files a Post-Test Year Adjustment Mechanism ("PTAM") that increases base tariff general rates for inflation. Federal, State and local environmental laws and regulations impose substantial compliance requirements on electricity and natural gas distribution utilities. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Electricity and natural gas distribution utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Utilities, and while Liberty Utilities believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

Liberty Utilities regularly works with its governing authorities to manage the affairs of the business.

### *Asset Retirement Obligations*

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases and other agreements, the probability of the agreements being extended, the likelihood of being required to incur such costs in the event there is an option to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations.

Liberty Utilities' facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Liberty Utilities has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging distribution facilities and expenses associated with providing new sources of commodity supply can generally be included in the facility's rate base and thus Liberty Utilities expects to be allowed to earn a return on such investment.

In conjunction with the recent acquisitions the Company assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements to: (i) removal of wind facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (clean of natural gas and PCB contaminants) and cap gas mains within the gas distribution and transmission system when mains are retired in place, or dispose of sections of gas main when removed from the pipeline system, (iii) clean and remove storage tanks containing waste oil and other waste contaminants, and (iv) remove asbestos upon major renovation or demolition of structures and facilities.

### *Environmental Risks*

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies.

APCo's ongoing operations and historic activities are subject to various environmental laws and regulations and are regulated by federal agencies such as the United States Environmental Protection Agency, Federal Energy Regulatory Commission (FERC), NERC, Environment Canada, Fisheries and Oceans Canada; State/Provincial Agencies such us, the New York State Department of Environmental Conservation ("NYSDEC"), California Air Resource Board, Connecticut Department of Environmental Protection ("CDEP"), Illinois Department of Environmental Protection ("IDEP'), Pennsylvania Game Commission ("PGC"), Alberta Environment, Manitoba Conservation, Ontario Ministry of the Environment, Ontario Ministry of Natural Resources, among others. Power generation facilities generate air emissions, noise, potential for flooding, spill risk, possible disruption of protected wildlife, along with the generation of industrial wastewater and certain amounts of hazardous wastes.

Liberty Utilities faces environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of an electrical distribution system are related to potential accidental release of mineral oil to the environment from non-operational events and the management of hazardous and universal waste in accordance with the various Federal, State and local environmental laws. Like most other industrial companies, Liberty Utilities generates some hazardous wastes as a result of its operations. Under Federal and State Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, Liberty Utilities investigates promptly all reported accidental releases to take all required remedial actions and manages hazardous waste and universal waste streams in accordance with the applicable Federal and State Legislation.

The primary risks associated with the operation of gas distribution systems are related to uncontrolled natural gas releases, equipment damage by construction equipment/third parties or severe weather events. The gas distribution assets are regulated by the Pipeline Hazardous Material Safety Administration (PHMSA) under the United States Department of Transportation and their respective State regulations in which the assets are located. Gas Distribution systems are subject to detailed inspections by State Regulatory Agencies to ensure adherence to applicable regulations. State Regulator Agencies review the Company's policies in reference to operation and maintenance, construction, training, emergency response, reporting, contractor management and measurements. Liberty monitors all aspects of pipeline safety and quickly mitigates any identified concerns.

The primary risks associated with the operation of power generation facilities are related to uncontrolled contaminant releases (or above the permitted limits), not being in continued compliance with permits and licenses obligations such as, continuous emissions monitoring, periodic reporting/source testing, general performance/operating conditions, operations adjustments (wind projects) resulting from post construction wildlife mortality monitoring, dam safety, potential accidental release of mineral oil or other hazardous materials to the environment.

The Liberty Utilities (East) region's ongoing operations and historic activities are subject to various federal, state and local environmental laws and regulations and are regulated by agencies such as the United States Environmental Protection Agency, the New Hampshire Department of Environmental Services ("NHDES"). Similar to other industrial companies, the gas and electric distribution utilities generate certain hazardous wastes. Under federal and state Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred. In the case of regulated utilities these costs are often allowed in rate case proceedings to be recovered from rate payers over a specified period.

Prior to their acquisition by Liberty Utilities, the EnergyNorth Gas Utility, the Granite State Electric Utility, and the New England Gas System were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("MGP") and related facilities. The Liberty Utilities is currently investigating and remediating, as necessary, those MGP and related sites where it is the lead project manager in accordance with plans submitted to the NHDES. The Liberty Utilities believes that obligations imposed on it because of those sites will not have a material impact on its results of operations or financial position.

Liberty Utilities estimates the remaining cost of these MGP-related environmental cleanup activities will be $77.7 million which at a discount rates ranging from 3.8% to 4.5% represents $69.6 million at December 31, 2013, which has been accrued as Liberty Utilities' estimate of costs for known issues. By rate orders, the Regulator provided for the recovery of site investigation and remediation costs and accordingly, at December 31, 2013 the Company has reflected a regulatory asset of $80.4 million for the remediation of the MGP and related sites.

APUC's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable.

### *Cycles and Season*

The hydroelectric operations of APCo are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized.

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

The Liberty Utilities (West) and Liberty Utilities (Central) regions' demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues.

Prior to January 1, 2013, the Liberty Utilities (West) region was exposed to volume sales risk related to seasonal weather variations at the CalPeco Electric System. Effective on January 1, 2013, pursuant to a CPUC approved Rate Case decision, a Base Revenue Requirement Balancing Account (BRRAM) rate mechanism has been implemented. The BRRAM removes the seasonal variations of the revenues and flattens the net revenue (minus Fuel, Purchased Power, and ECAC) to a monthly rate of $3.0 million or $36.0 million annually. This eliminates the risk of revenue variations associated with seasonal weather changes.

The Liberty Utilities (West) region's demand for energy is primarily affected by weather conditions and conservation initiatives. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. The Liberty Utilities (West) provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts to revenues; the BRRAM mitigates this risk.

The Liberty Utilities (East) and Liberty Utilities (Central) regions' natural gas demand is driven by the seasonal heating requirements of its residential, commercial, and industrial customer. That is, the colder the weather the greater the demand for natural gas to heat homes and businesses. As such, the Liberty Utilities (East) and Liberty Utilities (Central) regions' natural gas demand profiles typically peaks in the winter months of January and February and declines in the summer months of July and August. At the Peach State Gas System, a weather normalization adjustment is applied to customer bills during the months of October through May that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns.

***Litigation risks and other contingencies***

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

*Trafalgar proceedings*

Trafalgar commenced an action in 1999 in U.S. District Court against APUC, and various other entities related to them in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to APUC and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in the hydroelectric generating facilities in New York (the "Trafalgar Hydro Facilities"). In 2001, Trafalgar and other entities also filed for Chapter 11 reorganization in bankruptcy court and also filed a multi-count adversary complaint against certain subsidiary entities of APUC, which complaint was then transferred to the District Court. In 2006, the District Court decided that Aetna had complied with the provisions concerning the sale of the Trafalgar Class B Note, that APUC was therefore the holder and owner of the Trafalgar Class B Note, and that all other claims by Trafalgar with respect to the transfer of the Trafalgar Class B Note were without merit. Further, on November 6, 2008, the claims that were remaining in the District Court against APUC were dismissed by summary judgment. On October 22, 2009, Trafalgar filed an appeal from the November 6, 2008 summary judgment to the United States Court of Appeals for the Second Circuit. The Second Circuit Court of Appeals, among other things, on November 2, 2010 dismissed the claims against APUC in the civil proceedings. The bankruptcy proceedings are continuing, with a Second Circuit Court of Appeal hearing scheduled for December 12, 2012 to hear the appeal of the District Court's October 25, 2011 decision holding that APUC does not have a security interest in the monies transferred by Trafalgar before it filed for bankruptcy protection.

With respect to the civil proceedings, the United States Second Circuit Court of Appeals dismissed all the claims against APUC in the civil proceedings and remanded one issue to the District Court. On April 3, 2012, the District Court granted APUC summary judgment on its counter-claims against Trafalgar. The District Court found that Trafalgar was in default of the indenture and the loan agreements and that APUC was entitled to proceed to enforce its rights against its collateral. Trafalgar filed a notice of appeal of the Memorandum-Decision and Order. The appeal was argued on March 21, 2013. On March 25, 2013, the United States Second Circuit Court of Appeals affirmed the decision of the District Court giving APUC judgment on its claims. Trafalgar asked the United States Second Circuit Court of Appeals for reconsideration of its decision or to certify a legal question to the Connecticut Supreme Court. On May 21, 2013, the United States Second Circuit Court of Appeals denied Trafalgar's petition and the matter was sent back to the District Court for further proceedings with respect to the enforcement of APUC's remedies under the loan documents, including the calculation of the debt and the disposition of collateral. The District Court entered judgment in favor of APUC with regard to the default and APUC's entitlement to recourse to the collateral, but without determining the amount due under the note. The District Court then closed the case.

With respect to the bankruptcy proceedings, on January 30, 2013, the United States Second Circuit Court of Appeals held that Algonquin did have a security interest in Trafalgar's engineering malpractice claim and its proceeds. On February 20, 2013, Trafalgar filed a petition for a rehearing with the United States Second Circuit Court of Appeals, and in the alternative, sought to have the Second Circuit certify a legal question to the New York State Court of Appeals. The Second Circuit denied the petition and certification request which petition was denied on June 17, 2013. On September 16, 2013, Trafalgar filed a Petition for a Writ of Certiorari with the United States Supreme Court. Algonquin filed a brief in opposition to the Petition on October 18, 2013. On December 2, 2013, the United States Supreme Court denied Trafalgar's petition for a Writ of Certiorari. Algonquin filed and served a motion seeking an order terminating the automatic stay and directing the distribution of the funds held in the escrow account to Algonquin. Algonquin's motion for relief from the automatic stay has been denied without prejudice to re-filing the motion after the court determines the amount of Algonquin's claim and the validity of any defenses to the claim. Algonquin and Trafalgar have each filed motions with the Court seeking a determination of those issues. Those motions are under consideration by the Court.

*Côte Ste-Catherine Water Lease Dues*

On December 19, 1996, the Attorney General of Québec (the "Québec AG") filed suit in Québec Superior Court against Algonquin Dévelopment (Côte Ste-Catherine) Inc. (Dévelopment Hydromega), a predecessor company to an a subsidiary entity of APUC. The Québec AG at trial claimed $5.4 million for amounts that Algonquin Dévelopment Côte Ste-Catherine Inc. had been paying to Seaway Management under the water lease relating to the Côte Ste-Catherine hydroelectric generating facility. Algonquin Dévelopment (Côte Ste-Catherine) Inc. brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009, and the appeal was heard in January 2011.

On October 21, 2011 the Québec Court of Appeal ordered Algonquin Dévelopment (Côte Ste-Catherine) Inc. to pay approximately $5.4 million (including interest) to the government of Québec relating to water lease payments that Algonquin Dévelopment (Côte Ste-Catherine) Inc. has been paying to the Seaway Management under the water lease in prior years. The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. The potential unrecoverable loss, if any, for the related prior periods could be up to $6.0 million. The parties are attempting to resolve this matter through good faith negotiations.

*Long Sault Global Adjustment Claim*

In December 2012, N-R Power and Energy Corporation, Algonquin Power (Long Sault) Partnership, and N-R Power Partnership ("Long Sault") commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC's interpretation of certain provisions of a PPA between Long Sault and the OEFC, in relation to the use of the global Adjustment ("GA") as a price escalator. As a result of the OEFC's application of the new GA calculation to the calculation of total market cost of electricity ("TMC") of and, in turn, an index derived from TMC, the rate OEFC has paid to Long Sault under the PPA beginning with the application of OEFC's new TMC calculation in July 2011 has not escalated as contemplated in the PPA and term sheet. A Notice of Application was issued at the end of December 2012 with supporting materials filed at the end of April 2013. Cross examinations were held in November, 2013. A hearing is scheduled for early 2014.

*Dimos and Katsekas breach of contract claim*

On September 30, 2013, previous owners of the Clement Dam hydro facility, filed a demand for arbitration with Algonquin Power Fund (America) Inc. alleging breach of the Purchase Agreement and Royalty Agreement. The claim is for $1,345,257 for alleged breach of such agreements and $155,821 for alleged unpaid royalties. The plaintiffs have demanded arbitration pursuant to such agreements. An arbitration hearing date is scheduled for March, 2015.

*Synergics Energy Services, LLC, breach of contract claim*

On September 4, 2013, the plaintiff, previous owners of the Great Falls hydro facility, filed a complaint for alleged breach of the 2000 purchase and sale agreement and failure to pay a transfer payment thereunder in the event of the sale of the hydro facility. The claim is for $3,000,000 for alleged breach of the 2000 purchase and sale agreement. Discovery is being scheduled.

*Conex Energy-Canada, LLC and Conex Energy, Inc. breach of contract claim*

On October 31, 2013, the plaintiffs filed a complaint for, among other things, alleged breach of a confidential agreement in relation to the development and construction of the 10-megawatt solar photovoltaic Cornwall Solar project in Ontario, Canada. Plaintiffs attempted to serve Algonquin with the complaint on February 11, 2014.

*Bryson School District in Texas property taxes claim*

On February 10, 2014, APCo received correspondence from the Bryson School District in Texas regarding Senate Wind LLC's property taxes claiming the Senate Wind Facility owes an additional $2.2 million of property taxes based on an indemnity in the 2010 agreement with the school district. The assertion is being disputed.

### *Obligations to serve*

Liberty Utilities may have facilities located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, Liberty Utilities may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

# Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the eight quarter ended December 31, 2013:

| *Millions of dollars (except per share amounts)* | 1st Quarter 2013 | 2nd Quarter 2013 | 3rd Quarter 2013 | 4th Quarter 2013 |
|---|---|---|---|---|
| Revenue | $ 193.1 | $ 148.8 | $ 127.9 | $ 205.3 |
| Adjusted EBITDA | 61.8 | 56.5 | 40.5 | 67.6 |
| Net earnings / (loss) attributable to shareholders from continuing operations | 20.4 | 15.8 | 6.3 | 19.8 |
| Net earnings / (loss) attributable to shareholders | 19.2 | (18.1) | 6.0 | 13.1 |
| Net earnings / (loss) per share from continuing operations | 0.10 | 0.08 | 0.02 | 0.09 |
| Net earnings / (loss) per share | 0.10 | (0.09) | 0.02 | 0.06 |
| Adjusted net earnings | 19.4 | 15.4 | 6.9 | 18.5 |
| Adjust net earnings per share | 0.10 | 0.08 | 0.03 | 0.08 |
| Total Assets | 2,990.7 | 3,201.8 | 3,156.4 | 3,472.6 |
| Long term debt* | 917.5 | 1,091.5 | 1,092.0 | 1,255.6 |
| Dividend declared per common share | 0.08 | 0.09 | 0.09 | 0.09 |

| | 1st Quarter 2012 | 2nd Quarter 2012 | 3rd Quarter 2012 | 4th Quarter 2012 |
|---|---|---|---|---|
| Revenue | $ 58.1 | $ 58.7 | $ 93.0 | $ 138.9 |
| Adjusted EBITDA | 21.4 | 22.2 | 20.8 | 24.0 |
| Net earnings / (loss) attributable to shareholders from continuing operations | 2.0 | 5.3 | (0.6) | 6.8 |
| Net earnings/(loss) attributable to shareholders | 2.3 | 6.1 | (0.2) | 6.4 |
| Net earnings / (loss) per share from continuing operations | 0.01 | 0.03 | — | 0.04 |
| Net earnings/(loss) per share | 0.02 | 0.04 | — | 0.03 |
| Adjusted net earnings | 5.0 | 6.5 | 1.1 | 6.5 |
| Adjust net earnings per share | 0.04 | 0.04 | 0.01 | 0.03 |
| Total Assets | 1,265.6 | 1,416.0 | 1,967.1 | 2,779.0 |
| Long term debt[1] | 391.9 | 461.8 | 705.1 | 770.8 |
| Dividend declared per common share | 0.07 | 0.07 | 0.08 | 0.08 |

1 Long term debt includes current and long term portion of debt and convertible debentures

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $58.1 million and $205.3 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between net earnings attributable to shareholders of $19.2 million and a net loss of 18.1 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

## Disclosure Controls

At the end of the fiscal year ended December 31, 2013, APUC carried out an evaluation, under the supervision of and with the participation of APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a – 15(e) and Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2013, APUC's disclosure controls and procedures are effective.

## Internal controls over financial reporting

APUC's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of APUC; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of APUC are being made only in accordance with authorizations of management and directors of APUC; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of APUC's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

During the year ended December 31, 2013, APUC acquired the Shady Oaks Wind Facility, the Pine Bluff Water System, the Peach State Gas System and the New England Gas System. The financial information for these business acquisitions is included in this MD&A and in Note 3 to the consolidated financial statements. As permitted by National Instrument 52-109 and the U.S. Securities and Exchange Commission, the Company excluded these acquisitions from its evaluation of the effectiveness of APUC's internal controls over financial reporting as of December 31, 2013 due to the complexity associated with assessing internal controls during integration efforts and the proximity of some of the acquisitions to year-end.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2013 based on the criteria set forth in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on this evaluation, management has concluded that APUC's internal control over financial reporting was effective as of December 31, 2013.

During the year ended December 31, 2013, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. APUC continues to implement its internal control structure over the operations of the acquired businesses discussed above.

## Critical Accounting Estimates and Polices

The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to the useful lives and recoverability of depreciable assets, recoverability of deferred tax assets, rate-regulation, unbilled revenue, pension and post-employment benefits, fair value of derivatives and fair value of assets and liabilities acquired in a business combination. Actual results may differ from these estimates.

APUC's significant accounting policies are discussed in Note 1 to the consolidated financial statements. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

## Estimated useful lives and recoverability of Long-Lived Assets and Intangibles

The provisions for depreciation of utility property and equipment for financial reporting purposes are made on the straight-line method based on the estimated service lives of the assets. Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process. Non-regulated property and equipment are depreciated on a straight-line basis over useful lives of the related assets. Management believes the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries could result in a reduction of the estimated useful lives of those non-regulated assets or in an impairment write-down of the carrying value of these properties.

The carrying value of long-lived assets, including identifiable intangibles, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable. Some of the factors APUC considers as indicators of impairment include whether a facility is operating, its plan for return to service, external influences such as natural disasters, energy pricing and profitability and changes in regulation. Changes in circumstances, market conditions and estimates of future cash flows could negatively affect the recovery of APUC's assets and result in an impairment charge.

## Valuation of Deferred Tax Assets

Income taxes are accounted for using the asset and liability method. Under this method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities, as well as operating loss and tax credit carryforwards. The amount of deferred tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Although management believes the assumptions, judgments and estimates are reasonable, changes in tax laws and changes in operations could significantly impact the amounts provided for income taxes in our financial statements.

## Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to Liberty Utilities' operations. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or write down.

## Unbilled Energy Revenues

Revenues related to natural gas, electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of natural gas, energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

## Derivatives

APUC uses derivative instruments to manage exposure to changes in commodity prices, foreign exchange rates and interest rates. Derivative instruments that do not meet the normal purchases and sales exception are recorded at fair value. Changes in the derivative's fair value are recognized as regulatory assets or liabilities when the regulator permits recovery of the hedging strategy. For derivative designated in a cash flow hedge relationship, the effective portion of the change in fair value is deferred to accumulated other comprehensive income, until the hedged transaction occurs and is recognized in earnings. The ineffective portion is immediately recognized in earnings. For derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations, foreign currency transaction gain or loss that are effective as an economic hedge of the net investment in a foreign operation are reported in other comprehensive income.

Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management's judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets adjusted for nonperformance risk. A significant change in estimate could affect APUC's results of operations if the hedging relationship was considered no longer effective.

## Pension and Post-employment Benefits

In conjunction with recent utilities acquisitions, the Company assumed defined benefit pension and post-employment benefit plans for qualifying employees in the related acquired businesses. The obligations and related costs are calculated using actuarial concepts, which include critical assumptions related to the discount rate, expected rate of return on plan assets and medical cost trend rates. These assumptions are important elements of expense and/or liability measurement and are updated on an annual basis, or upon the occurrence of significant events. A significant change in estimate could affect APUC's results of operations.

## Fair value of assets and liabilities acquired in a business combination

The Company has closed a number of business acquisitions in the past few years. Management's judgment is required to estimate the purchase price, to identify and to fair value all assets and liabilities acquired. The determination of the fair value of assets and liabilities acquired is based upon management's estimates and certain assumptions generally included in a present value calculation of the related cash flows. A significant change in estimate could affect APUC's results of operations.

Additional disclosure of APUC's critical accounting estimates is also available SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

# MANAGEMENT'S REPORT

## Financial Reporting

The preparation and presentation of the accompanying Consolidated Financial Statements, MD&A and all financial information in the Financial Statements are the responsibility of management and have been approved by the Board of Directors. The Financial Statements have been prepared in accordance with U.S. generally accepted accounting principles. Financial statements, by nature include amounts based upon estimates and judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Management has prepared the financial information presented elsewhere in this document and has ensured that it is consistent with that in the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit Committee of the Board of Directors, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit Committee reports its findings to the Board of Directors for its consideration in approving the consolidated financial statements for issuance to the shareholders.

## Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2013, based on the framework established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2013.

During the year ended December 31, 2013, APUC acquired Shady Oaks Holdings, TianRun Shady Oaks LLC, GSG 6 LLC, Liberty Utilities (Pine Bluff Water) Inc., Liberty Utilities (Peach State Natural Gas) Corp. and Liberty Utilities (New England Natural Gas Company) Corp. As of December 31, 2013, these acquired entities represent 16% of total assets and represent 10% and 17% of revenue and earnings from continuing operations before income taxes, respectively, for the year then ended. As permitted by National Instrument 52-109 and the U.S. Securities and Exchange Commission, Management excluded these acquisitions from its evaluation of the effectiveness of the Company's internal controls over financial reporting as of December 31, 2013 due to the complexity associated with assessing internal controls during integration efforts and the proximity of certain of the acquisitions to year-end.

The Company also excluded the 2012 acquisitions of Liberty Utilities (Granite State Electric) Corp., Liberty Utilities (EnergyNorth Natural Gas) Corp., Liberty Utilities (Midstates Natural Gas) Corp. and Wind Portfolio SponsorCo LLC from its evaluation of the effectiveness of APUC's internal controls over financial reporting as of December 31, 2012 due to the complexity associated with assessing internal controls during integration efforts and the proximity of some of the acquisitions to year-end. The 2012 acquisitions were associated with total assets of $1,494.5 million and total revenues of $116.1 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2012.

March 14, 2014

| | |
|---|---|
| Ian Robertson | David Bronicheski |
| Chief Executive Officer | Chief Financial Officer |

# INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM TO SHAREHOLDERS

## Report on financial statements

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp., which comprise the consolidated balance sheet as at December 31, 2013 and the consolidated statements of operations, comprehensive income (loss), equity, and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

## Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

## Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

EY

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## Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as at December 31, 2013, and the consolidated results of its operations and its cash flows for the year ended December 31, 2013, in conformity with United States generally accepted accounting principles.

## Other matter

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated March 14, 2014 expressed an unqualified opinion on Algonquin Power & Utilities Corp.'s internal control over financial reporting.

Ernst & Young LLP

Toronto, Canada
March 14, 2014

Chartered Accountants,
Licensed Public Accountants

A member firm of Ernst & Young Global Limited

# INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM TO SHAREHOLDERS

## Report on internal controls under standards of the Public Company Accounting Oversight Board (United States)

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). Algonquin Power & Utilities Corp.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included under the heading Internal controls over financial reporting in Management's Discussion and Analysis for the year ended December 31, 2013. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

EY

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As indicated under the heading Internal controls over financial reporting in Management's Discussion and Analysis, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Shady Oaks Holdings, TianRun Shady Oaks LLC, GSG 6 LLC, Liberty Utilities (Pine Bluff Water) Inc., Liberty Utilities (Peach State Natural Gas) Corp. and Liberty Utilities (New England Natural Gas Company) Corp., which are included in the 2013 consolidated financial statements of Algonquin Power & Utilities Corp. and constituted 16% of total assets, as of December 31, 2013, and 10% and 17% of revenue and earnings from continuing operations before income taxes, respectively, for the year then ended. Our audit of internal control over financial reporting of Algonquin Power & Utilities Corp. also did not include an evaluation of the internal control over financial reporting of Shady Oaks Holdings, TianRun Shady Oaks LLC, GSG 6 LLC, Liberty Utilities (Pine Bluff Water) Inc., Liberty Utilities (Peach State Natural Gas) Corp. and Liberty Utilities (New England Natural Gas Company) Corp.

In our opinion, Algonquin Power & Utilities Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Algonquin Power & Utilities Corp. as of December 31, 2013, and the related consolidated statements of comprehensive income (loss), equity, and cash flows for the year ended December 31, 2013 of Algonquin Power & Utilities Corp. and our report dated March 14, 2014 expressed an unqualified opinion thereon.

Ernst & Young LLP

Toronto, Canada
March 14, 2014

Chartered Accountants,
Licensed Public Accountants

A member firm of Ernst & Young Global Limited

**KPMG LLP**
**Chartered Professional Accountants**
Bay Adelaide Centre
333 Bay Street, Suite 4600
Toronto, Ontario M5H 2S5
Canada

Telephone (416) 777-8500
Fax (416) 777-8818
Internet www.kpmg.ca

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated balance sheet of Algonquin Power & Utilities Corp. as of December 31, 2012, and the related consolidated statements of operations, comprehensive income (loss), equity and cash flows for the year then ended. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as of December 31, 2012, and its consolidated results of operations and its consolidated cash flows for the year then ended in conformity with US generally accepted accounting principles.

The consolidated financial statements as at and for the year ended December 31, 2012 have been restated to retrospectively account for a component of the Company that was determined to meet requirements for asset held for sale classification and discontinued operations presentation in the year ended December 31, 2013 as disclosed in note 20 to the consolidated financial statements for the years ended December 31, 2013 and 2012.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada

March 14, 2013 except for the asset held for sale and discontinued operations adjustments to the 2012 comparative amounts discussed in note 20, which is as of March 14, 2014

# Algonquin Power & Utilities Corp.
# Audited Consolidated Balance Sheets

*(thousands of Canadian dollars)*

| | December 31, 2013 | December 31, 2012 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 13,839 | $ 53,122 |
| Accounts receivable, net (note 4) | 156,712 | 88,359 |
| Natural gas in storage (note 1(g)) | 25,609 | 19,279 |
| Supplies and consumables inventory | 7,924 | 4,233 |
| Regulatory assets (note 7) | 34,643 | 10,644 |
| Due from related parties (note 21) | — | 816 |
| Prepaid expenses | 11,341 | 10,861 |
| Notes receivable (note 8) | 598 | 537 |
| Deferred tax asset (note 19) | 19,652 | 10,567 |
| Income tax receivable (note 19) | 379 | 556 |
| Derivative instruments (note 26) | 9,176 | 7,020 |
| Assets held for sale (note 20) | 23,927 | 26,900 |
| | 303,800 | 232,894 |
| Property, plant and equipment (note 5) | 2,708,704 | 2,086,278 |
| Intangible assets (note 6) | 54,416 | 56,781 |
| Assets held for sale (note 20) | — | 76,437 |
| Goodwill (note 6) | 84,647 | 61,459 |
| Regulatory assets (note 7) | 155,705 | 123,748 |
| Derivative instruments (note 26) | 27,123 | 6,230 |
| Long-term investments and notes receivable (note 8) | 32,746 | 37,646 |
| Deferred non-current income tax asset (note 19) | 86,632 | 77,497 |
| Other assets (note 13) | 18,784 | 20,020 |
| | $ 3,472,557 | $ 2,778,990 |

# Algonquin Power & Utilities Corp.
# Audited Consolidated Balance Sheets

*(thousands of Canadian dollars)*

| | December 31, 2013 | December 31, 2012 |
|---|---|---|
| **LIABILITIES AND EQUITY** | | |
| Current liabilities: | | |
| Accounts payable | $ 14,489 | $ 34,271 |
| Accrued liabilities | 142,414 | 95,708 |
| Due to related parties (note 21) | — | 1,811 |
| Dividends payable (note 18) | 17,535 | 15,498 |
| Regulatory liabilities (note 7) | 21,632 | 8,626 |
| Long term liabilities (note 9) | 8,339 | 1,768 |
| Pension and other post-employment benefits (note 11) | 305 | — |
| Other long term liabilities (note 14) | 7,451 | 4,352 |
| Advances in aid of construction (note 1(o)) | 1,239 | 591 |
| Derivative instruments (note 26) | 2,492 | 2,211 |
| Environmental obligations (note 23(a)(ii)) | 10,111 | 2,523 |
| Preferred shares series C (note 12) | 1,038 | — |
| Liabilities held for sale (note 20) | 1,471 | 1,211 |
| Income tax liability (note 19) | 5,159 | 539 |
| Deferred credits (note 19) | 7,778 | 5,754 |
| Deferred income tax liability (note 19) | 2,308 | 1,133 |
| | 243,761 | 175,996 |
| Long-term liabilities (note 9) | 1,247,249 | 769,058 |
| Convertible debentures (note 10) | — | 960 |
| Advances in aid of construction (note 1(o)) | 77,697 | 71,626 |
| Regulatory liabilities (note 7) | 101,657 | 82,050 |
| Deferred income tax liability (note 19) | 137,153 | 100,798 |
| Derivative instruments (note 26) | 13,729 | 15,605 |
| Deferred credits (note 19) | 17,115 | 25,816 |
| Pension and other post-employment benefits (note 11) | 70,532 | 59,246 |
| Environmental obligation (note 23(a)(ii)) | 59,444 | 54,817 |
| Other long-term liabilities (note 14) | 20,492 | 20,889 |
| Preferred shares series C (note 12) | 17,767 | — |
| | 1,762,835 | 1,200,865 |
| Equity: | | |
| Preferred shares (note 15(b)) | 116,546 | 116,546 |
| Common shares (note 15(a)) | 1,351,264 | 1,245,326 |
| Subscription receipts (note 15(a)(ii)) | — | 61,160 |
| Additional paid-in capital | 7,313 | 5,224 |
| Deficit | (488,406) | (406,143) |
| Accumulated other comprehensive loss (note 16) | (31,410) | (104,867) |
| Total Equity attributable to shareholders of Algonquin Power & Utilities Corp. | 955,307 | 917,246 |
| Noncontrolling interests | 510,654 | 484,883 |
| Total Equity | 1,465,961 | 1,402,129 |
| Commitments and contingencies (note 23) | | |
| Subsequent events (notes 9, 15, 18, 20 and 23) | | |
| | $ 3,472,557 | $ 2,778,990 |

See accompanying notes to consolidated financial statements

# Algonquin Power & Utilities Corp.
# Audited Consolidated Statements of Operations

*(thousands of Canadian dollars, except per share amounts)*

| | 2013 | 2012 |
|---|---|---|
| **Revenue:** | | |
| Regulated electricity sales and distribution | $ 166,156 | $ 108,457 |
| Regulated gas sales and distributions | 261,672 | 75,718 |
| Regulated water reclamation and distribution | 57,350 | 46,423 |
| Non-regulated energy sales | 180,191 | 114,351 |
| Other revenue | 9,922 | 3,857 |
| | 675,291 | 348,806 |
| **Expenses** | | |
| Operating | 188,952 | 117,826 |
| Regulated electricity purchased | 97,376 | 68,209 |
| Regulated gas purchased | 148,784 | 37,461 |
| Non-regulated fuel for generation | 17,151 | 14,589 |
| Depreciation of property, plant and equipment | 91,978 | 45,187 |
| Amortization of intangible assets | 4,200 | 4,151 |
| Administrative expenses | 23,518 | 19,572 |
| Gain on foreign exchange | (567) | (561) |
| | 571,392 | 306,434 |
| **Operating income from continuing operations** | 103,899 | 42,372 |
| Interest expense | 53,345 | 35,620 |
| Interest, dividend income and other income | (7,785) | (7,239) |
| Loss on sale of assets | 750 | — |
| Acquisition-related costs | 2,140 | 7,688 |
| Gain on derivative financial instruments (note 26(b)(iv)) | (5,200) | (233) |
| | 43,250 | 35,836 |
| **Earnings from continuing operations before income taxes** | 60,649 | 6,536 |
| **Income tax expense (recovery) (note 19)** | | |
| Current | 2,526 | 738 |
| Deferred | 6,629 | (15,105) |
| | 9,155 | (14,367) |
| Earnings from continuing operations | 51,494 | 20,903 |
| Income/(loss) from discontinued operations net of tax (note 20) | (42,011) | 1,043 |
| **Net earnings** | 9,483 | 21,946 |
| Net earnings/(loss) attributable to noncontrolling interests | (10,813) | 7,414 |
| **Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.** | $ 20,296 | $ 14,532 |
| Basic net earnings per share from continuing operations (note 22) | $ 0.28 | $ 0.08 |
| Basic net earnings/(loss) per share from discontinued operations (note 22) | (0.21) | 0.01 |
| Basic net earnings per share (note 22) | 0.07 | 0.09 |
| Diluted net earnings per share from continuing operations (note 22) | 0.28 | 0.08 |
| Diluted net earnings/(loss) per share from discontinued operations (note 22) | (0.20) | 0.01 |
| Diluted net earnings per share (note 22) | $ 0.07 | $ 0.09 |

See accompanying notes to consolidated financial statements

# Algonquin Power & Utilities Corp.
# Audited Consolidated Statements of Comprehensive Income (Loss)

(thousands of Canadian dollars)

| | | 2013 | | 2012 |
|---|---|---|---|---|
| Net earnings | $ | 9,483 | $ | 21,946 |
| Other comprehensive income (loss): | | | | |
| Foreign currency translation adjustment, net of tax of $149 and tax recovery of $388, respectively (notes 1(v), 26(b)(iii) and 26(c)) | | 81,597 | | (9,399) |
| Change in fair value of cash flow hedge, net of tax expense of $5,103 and $1,715, respectively (note 26(b)(ii)) | | 17,308 | | 5,168 |
| Change in unrealized pension and other post-retirement expense, net of tax expense of $10,896 and tax recovery of $1,653, respectively (note 11) | | 16,727 | | (2,458) |
| Other comprehensive income (loss), net of tax | | 115,632 | | (6,689) |
| Comprehensive income | | 125,115 | | 15,257 |
| Comprehensive income attributable to the noncontrolling interests | | 31,362 | | 9,082 |
| Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp. | $ | 93,753 | $ | 6,175 |

See accompanying notes to consolidated financial statements

# Algonquin Power & Utilities Corp.
# Audited Consolidated Statement of Equity
**(thousands of Canadian dollars)**

For the year ended December 31, 2013:

| | Common Shares | Preferred Shares | Subscription Receipts | Additional paid-in capital | Accumulated Deficit | Accumulated OCI | Non-controlling interests | Total |
|---|---|---|---|---|---|---|---|---|
| Balance, December 31, 2012 | $1,245,326 | $116,546 | $ 61,160 | $ 5,224 | $ (406,143) | $ (104,867) | $484,883 | $1,402,129 |
| Net earnings/(loss) | — | — | — | — | 20,296 | — | (10,813) | 9,483 |
| Other comprehensive income | — | — | — | — | — | 73,457 | 42,175 | 115,632 |
| Dividends declared and distributions to non-controlling interests | — | — | — | — | (59,773) | — | (5,591) | (65,364) |
| Dividends and issuance of shares under dividend reinvestment plan | 13,970 | — | — | — | (13,970) | — | — | — |
| Exercise and conversion of subscription receipts | 90,464 | — | (90,464) | — | — | — | — | — |
| Exercise of subscription receipts | — | — | 29,304 | — | — | — | — | 29,304 |
| Conversion and redemption of convertible debentures | 960 | — | — | — | — | — | — | 960 |
| Issuance of common shares under employee share purchase plan | 544 | — | — | — | (17) | — | — | 527 |
| Share-based compensation | — | — | | 2,089 | — | — | — | 2,089 |
| Preferred Series C shares | — | — | — | — | (18,497) | — | — | (18,497) |
| Acquisition of non-controlling interest (notes 3(i) and 21) | — | — | — | — | (10,302) | — | — | (10,302) |
| Balance, December 31, 2013 | $1,351,264 | $116,546 | $ — | $ 7,313 | $ (488,406) | $ (31,410) | $510,654 | $1,465,961 |

# Algonquin Power & Utilities Corp.
# Audited Consolidated Statement of Equity
**(thousands of Canadian dollars)**

For the year ended December 31, 2012:

| | Common Shares | Preferred Shares | Subscription Receipts | Additional paid-in capital | Accumulated Deficit | Accumulated OCI | Non-controlling interests | Total |
|---|---|---|---|---|---|---|---|---|
| Balance, December 31, 2011 | $ 975,263 | $ — | $ — | $ 1,525 | $ (366,080) | $ (96,510) | $ 38,497 | $ 552,695 |
| Net earnings | — | — | — | — | 14,532 | — | 7,414 | 21,946 |
| Other comprehensive income /(loss) | — | — | — | — | — | (8,357) | 1,668 | (6,689) |
| Dividends declared and distributions to non-controlling interests | — | — | — | — | (43,619) | — | (2,640) | (46,259) |
| Dividends and issuance of shares under dividend reinvestment plan | 7,343 | — | — | — | (7,343) | — | — | — |
| Exercise and conversion of subscription receipts | 142,609 | — | — | — | — | — | — | 142,609 |
| Issuance of subscription receipts | — | — | 61,160 | — | — | — | — | 61,160 |
| Conversion and redemption of convertible debentures | 118,779 | — | — | (689) | — | — | — | 118,090 |
| Issuance of common shares under employee share purchase plan | 432 | — | — | — | — | — | — | 432 |
| Stock compensation expense | — | — | — | 1,956 | — | — | — | 1,956 |
| Public offering related taxes | 900 | — | — | — | — | — | — | 900 |
| Issuance of preferred shares | — | 116,546 | — | — | — | — | — | 116,546 |
| Acquisition of 49.99% of Liberty Energy (California) | — | — | — | — | (3,633) | — | (35,023) | (38,656) |
| Acquisition of U.S. Wind farms | — | — | — | 2,432 | — | — | 474,967 | 477,399 |
| Balance, December 31, 2012 | $1,245,326 | $116,546 | $ 61,160 | $ 5,224 | $ (406,143) | $ (104,867) | $484,883 | $1,402,129 |

See accompanying notes to consolidated financial statements

# Algonquin Power & Utilities Corp.
# Audited Consolidated Statements of Cash Flows

*(thousands of Canadian dollars)*

| | 2013 | 2012 |
|---|---|---|
| **Cash provided by (used in):** | | |
| **Operating Activities:** | | |
| Net earnings from continuing operations | $ 51,494 | $ 20,903 |
| Adjustments and items not affecting cash: | | |
| Depreciation of property, plant and equipment | 91,978 | 45,187 |
| Amortization of intangible assets | 4,200 | 4,151 |
| Other amortization | 2,891 | 2,175 |
| Deferred taxes | 6,629 | (15,105) |
| Unrealized gain on derivative financial instruments | (6,758) | (3,127) |
| Share-based compensation | 2,000 | 1,956 |
| Cost of equity funds used for construction purposes | (1,786) | — |
| Pension and post retirement expense | (302) | 2,852 |
| Loss on sale of long lived assets | 750 | — |
| Changes in non-cash operating items (note 24) | (47,819) | (3,476) |
| Changes in non-cash operating items from discontinued operations (note 24) | 36 | (408) |
| Cash provided/(used) in discontinued operations (note 20) | (4,388) | 7,846 |
| | 98,925 | 62,954 |
| **Financing Activities:** | | |
| Cash dividends on common shares | (52,335) | (36,917) |
| Cash dividends on preferred shares | (5,400) | (769) |
| Cash distributions to noncontrolling interests | (5,591) | (2,640) |
| Issuance of common shares | 29,983 | 143,041 |
| Proceeds from subscription receipts | — | 61,160 |
| Issuance of preferred shares | — | 115,300 |
| Deferred financing costs | (2,240) | (5,435) |
| Increase in long-term liabilities | 950,346 | 505,542 |
| Decrease in long-term liabilities | (685,472) | (75,432) |
| Increase in advances in aid of construction | 2,299 | 1,051 |
| Decrease in other long-term liabilities | (1,574) | (860) |
| | 230,016 | 704,041 |
| **Investing Activities:** | | |
| Decrease in restricted cash | 1,430 | 805 |
| Increase in other assets | (3,004) | (2,481) |
| Distributions received in excess of equity income | 727 | 343 |
| Proceeds from sale of discontinued operations | 24,968 | — |
| Receipt of principal on notes receivable | 109 | 1,894 |
| Additions to property, plant and equipment | (158,377) | (75,692) |
| Additions to intangibles | — | (2,237) |
| Acquisitions of operating entities | (239,014) | (669,905) |
| Acquisition of noncontrolling interest | — | (38,756) |
| Proceeds from sale of long lived assets | 3,408 | 204 |
| | (369,753) | (785,825) |
| Effect of exchange rate differences on cash | 1,529 | (935) |
| Decrease in cash and cash equivalents | (39,283) | (19,765) |
| Cash and cash equivalents, beginning of the period | 53,122 | 72,887 |
| Cash and cash equivalents, end of the period | $ 13,839 | $ 53,122 |

| **Supplemental disclosure of cash flow information:** | **2013** | **2012** |
|---|---|---|
| Cash paid during the period for interest expense | $ 44,185 | $ 28,635 |
| Cash paid during the period for income taxes | $ 1,107 | $ 252 |
| Non-cash transactions | | |
| Property, plant and equipment acquisitions in accruals | $ 10,829 | $ 10,495 |

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC's principal activity is the ownership of power generation facilities and water, gas and electric utilities, through investments in securities of subsidiaries including corporations, limited partnerships and trusts which carry on these businesses.

APUC's power generation business unit conducts business under the name Algonquin Power Co. ("APCo"). APCo owns or has interests in renewable energy facilities and thermal energy facilities. APUC's Utility Services business unit conducts business under the name of Liberty Utilities Co. ("Liberty Utilities"). Liberty Utilities operates a portfolio of utilities in the United States of America providing electric, natural gas, water distribution or wastewater services.

## 1. Significant accounting policies

### (a) Basis of preparation

The accompanying consolidated financial statements and accompanying notes have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP") and follow disclosures required under Regulation S-X provided by the Securities and Exchange Commission ("SEC").

### (b) Basis of consolidation

The accompanying consolidated financial statements of APUC include the accounts of APUC and its wholly owned subsidiaries and variable interest entities ("VIEs") where the Company is the primary beneficiary. Intercompany transactions and balances have been eliminated.

### (c) Accounting for rate regulated operations

The regulated utility operating companies owned by Liberty Utilities are subject to rate regulation generally overseen by the public utility commissions of the states in which they operate (the "Regulator"). The Regulator provides the final determination of the rates charged to customers. APUC's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Included in Note 7, Regulatory Assets & Liabilities are details of regulatory assets and liabilities, and their current regulatory treatment.

In the event the Company determines that its net regulatory assets are not probable of recovery, it would no longer apply the principles of the current accounting guidance for rate regulated enterprises and would be required to record an after-tax, non-cash charge (credit) against income for any remaining regulatory assets (liabilities). The impact could be material to the Company's reported financial condition and results of operations.

The electric and gas utilities' and the water utilities' accounts are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC") and National Association of Regulatory Utility Commissioners, respectively.

### (d) Cash and cash equivalents

Cash and cash equivalents include all highly liquid instruments with an original maturity of three months or less.

### (e) Restricted cash

Restricted cash represent reserves and amounts set aside pursuant to requirements of various debt agreements and requirements of ISO New England, Inc. Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash as part of other assets (note 13) in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

*(in thousands of Canadian dollars except as noted and amounts per share)*

**1. Significant accounting policies (continued)**

(f) Accounts receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses adjusted to take into account current market conditions and customers' financial condition, the amount of receivables in dispute, and the receivables aging and current payment patterns. Account balances are charged against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. The Company does not have any off-balance sheet credit exposure related to its customers.

(g) Gas in storage

Gas in storage is reflected at weighted average cost or first-in-first-out as required by regulators and represents natural gas and liquefied natural gas that will be utilized in the ordinary course of business of the gas utilities. Existing rate orders allow the Company to pass through the cost of gas purchased directly to the rate payers along with any applicable authorized delivery surcharge adjustments. Accordingly, the recoverable value of gas in storage does not fall below the cost to the Company (note 7).

(h) Supplies and consumables inventory

Supplies and consumables inventory (other than capital spares and rotatable spares, which are included in property, plant, and equipment) are charged to inventory when purchased and then capitalized to plant or expensed, as appropriate, when installed, used or become obsolete. These items are stated at the lower of cost and replacement cost.

(i) Property, plant and equipment:

Property, plant and equipment, consisting of renewable and thermal generation assets, electrical, gas, water and wastewater distribution assets, equipment and land, are recorded at cost. The costs of acquiring or constructing property, plant and equipment include the following: materials, labour, contractor and professional services, construction overhead directly attributable to the capital project (where applicable), interest for non-regulated property and allowance for equity funds used during construction ("AFUDC") for regulated property. Plant and equipment under capital leases are initially recorded at cost determined as the present value of minimum lease payments.

AFUDC represents the cost of borrowed funds (allowance for borrowed funds used during construction) and a return on other funds (allowance for equity funds used during construction). Under ASC 980, an allowance for funds used during construction projects that are included in rate base is capitalized. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation. For operations that do not apply regulatory accounting, interest related only to debt is capitalized as a cost of construction in accordance with ASC 835. The interest capitalized that relates to debt reduces interest expense on the consolidated statements of operations. The AFUDC capitalized that relates to equity funds is recorded as interest, dividend and other income on the consolidated statements of operations.

| | 2013 | 2012 |
|---|---|---|
| Interest capitalized on non-regulated property | $ 669 | $ 1,036 |
| AFUDC capitalized on regulated property: | | |
| Allowance for borrowed funds | 1,055 | 628 |
| Allowance for equity funds | 1,786 | 1,108 |
| Total | $ 3,510 | $ 2,772 |

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred.

*(in thousands of Canadian dollars except as noted and amounts per share)*

**1. Significant accounting policies (continued)**

(i) Property, plant and equipment (continued)

Investment tax credits and government grants are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset as a reduction to depreciation expense. Contributions in aid of construction represent amounts contributed by customers and governments and developers for the cost of utility capital assets. It also includes amounts initially recorded as advances in aid of construction (note 1(o)) but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset as a reduction to depreciation expense.

The Company's depreciation is based on the estimated useful lives of the depreciable assets in each category and is determined using the straight-line method. The range of estimated useful lives and the weighted average useful lives are summarized below:

| | Range of useful lives | | Weighted average useful lives | |
|---|---|---|---|---|
| | **2013** | **2012** | **2013** | **2012** |
| Generation | | | | |
| Renewable | 3 – 60 | 3 – 60 | 35 | 32 |
| Thermal | 3 – 40 | 3 – 40 | 24 | 23 |
| Distribution | | | | |
| Gas | 5 – 80 | 5 – 80 | 38 | 38 |
| Electrical | 8 – 75 | 8 – 75 | 41 | 42 |
| Water & wastewater | 5 – 50 | 5 – 50 | 39 | 25 |
| Equipment | 5 – 50 | 5 – 50 | 24 | 21 |

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of Liberty Utilities are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operation in the future through adjustments to depreciation expense. In the absence of regulator-approved accounting policies, gains and losses on the disposition of property, plant and equipment are charged to earnings as incurred.

(j) Intangibles

The fair value of power sales contracts acquired in business combinations are amortized on a straight-line basis over the remaining term of the contract. These periods range from 6 to 25 years from date of acquisition.

Customer relationships acquired in business combinations are amortized on a straight-line basis over their estimated life of 40 years.

(k) Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the net assets acquired. Goodwill is not included in the rate-base on which regulated utilities are allowed to earn a return and is not amortized.

The Company annually assesses qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If it is more likely than not that a reporting unit's fair value is less than its carrying amount, the Company calculates the fair value of the reporting unit. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value. Goodwill is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

**1. Significant accounting policies (continued)**

(l) Impairment of long-lived assets

APUC reviews property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable.

Assets Held and Used: Recoverability of assets expected to be held and used is measured by comparing the carrying amount of an asset to undiscounted expected future cash flows. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value.

Assets Held for Sale: Recoverability of assets held for sale is measured by comparing the carrying amount of an asset to its fair value less the cost to sell. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value less estimated costs to sell.

(m) Variable interest entities

The Company performs analyses to assess whether its operations and investments represent variable interest entities ("VIEs"). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly-owned facilities. VIEs of which the Company is deemed the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the right to receive benefits or the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where APUC is not deemed the primary beneficiary, the VIE is not consolidated.

Long Sault is a hydroelectric generating facility in which APUC acquired an interest by way of subscribing to two notes from the original developers. The notes receivable effectively provide APUC the right to 65% after tax cash flows of the facility from 2014 to 2027 and 58% thereafter. The Company also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038. Effective December 31, 2013, APUC acquired an equity interest in Long Sault (note 21). APUC has determined that the facility is a VIE since the Company is the primary beneficiary and therefore the Long Sault entity is subject to consolidation by the Company. Total net book value of generating assets and long-term debt of Long Sault amounts to $44,319 (2012 - $42,566) and to $37,143 (2012 - $38,136), respectively. The Long Sault debt only has recourse over the Long Sault generating assets. The financial performance of Long Sault reflected on the statement of operations includes non-regulated energy sales of $10,155 (2012 - $8,747), operating expenses and amortization of $2,391 (2012 - $2,728) and interest expense of $3,632 (2012 - $3,929).

(n) Long-term investments and notes receivable

Investments in which APUC has significant influence but are not controlled are accounted using the equity method. APUC records its share in the income or loss of its investees in interest, dividend and other income in the consolidated statements of operations.

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable that exceed one year and bear interest at a market rate based on the customer's credit quality are initially recorded at cost, which is generally face value. Subsequent to acquisition, they are recorded at amortized cost using the effective interest method. The Company acquired these notes receivable as long-term investments and does not intend to sell these instruments prior to maturity.

If a loss in value of a long-term investment is considered other than temporary, an allowance for impairment on the investment is recorded for the amount of that loss. An allowance for impairment loss on notes receivable is recorded if it is expected that the Company will not collect all principal and interest contractually due. The impairment is measured based on the present value of expected future cash flows discounted at the note's effective interest rate.

(o) Advances in aid of construction

The Company's regulated utilities have various agreements with real estate development companies (the "developers") conducting business within the Company's utility service territories, whereby funds are advanced to the Company by the developers to assist with funding some or all of the costs of the development. These amounts are recorded as Advances in Aid of Construction in other long-term liabilities.

**1. Significant accounting policies (continued)**

(o) Advances in aid of construction (continued)

In many instances, developer advances can be subject to refund but the refund is non-interest bearing. Refunds of developer advances are made over periods generally ranging from 10 to 20 years. Advances not refunded within the prescribed period are usually not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to the cost of property, plant and equipment. In 2013, $627 (2012 - $3,555) was transferred from advances in aid of construction to contributions in aid of construction.

(p) Deferred water rights and customer deposits

Deferred water rights are related to a hydroelectric generating facility which has a fifty year water lease with the first ten years of the water lease requiring no payment, which is a form of lease inducement. An annual average rate for water rights was estimated for the entire life of the lease and that average rate is being expensed over the lease term. The result of this policy is that the deferred water rights inducement amount recorded in the first ten years is being drawn down in the last forty years.

Customer deposits result from the Liberty Utilities' obligation by state regulators to collect a deposit from customers of its facilities under certain circumstances when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement. The deposits bear monthly interest and are applied to the customer account after 12 months if the customer is found to be credit worthy.

(q) Pension and other post-employment plans

The Company has established defined contribution pension plans, defined benefit pension plans, and other post-employment benefit ("OPEB") plans for its various employee groups in Canada and the United States. The Company recognizes the funded status of its defined benefit pension plans and other post employment benefit plans on the consolidated balance sheets. The Company's expense and liabilities are determined by actuarial valuations, using assumptions that are evaluated annually at December 31, including discount rates, mortality, assumed rates of return, compensation increases, turnover rates and healthcare cost trend rates. The impact of modifications to those assumptions and modifications to prior services are recorded as actuarial gains and losses in accumulated other comprehensive income and amortized to net periodic cost over future periods using the corridor method. The costs of the Company's pension for employees are expensed over the periods during which employees render service and are recognized as part of administrative expenses in the consolidated statements of operations.

(r) Asset retirement obligations

The Company recognizes a liability for asset retirement obligations based on the fair value of the liability when incurred, which is generally upon acquisition, construction, development or through the normal operation of the asset. Concurrently, the Company also capitalizes an asset retirement cost, equal to the estimated fair value of the asset retirement obligation, by increasing the carrying value of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in depreciation expense on the consolidated statements of operations, or regulatory assets when the amount is recoverable through rates. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the consolidated statements of operations, or regulatory assets when the amount is recoverable through rates. Actual expenditures incurred are charged against the accumulated obligation.

(s) Stock based compensation

The Company has several share-based compensation plans: a share option plan; an employee common share purchase plan ("ESPP"); a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. The Company recognizes all employee stock-based compensation as a cost in the financial statements. Equity classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value of options using the Black-Scholes option pricing model.

**1. Significant accounting policies (continued)**

(t) Noncontrolling interests

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to the equity holders of the parent Company. Noncontrolling interests are initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of earnings and other comprehensive income attributable to the noncontrolling interests and any dividends or distributions paid to the noncontrolling interests.

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to the equity holders of the parent Company. Noncontrolling interests are initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of earnings and other comprehensive income attributable to the noncontrolling interests and any dividends or distributions paid to the noncontrolling interests.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net earnings or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

Certain of the Company's U.S. based wind businesses are organized as limited liability corporations and partnerships and have noncontrolling Class A membership equity investors ("Class A partnership units") which are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. The share of earnings attributable to the noncontrolling interest holders in these subsidiaries is calculated using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting. HLBV uses a balance sheet approach, which measures the allocation of income or loss of the Class A's membership in each period by calculating the change in the amount of distribution the partners would contractually be entitled to based on a hypothetical liquidation of the book value carrying amounts of the entity at the beginning of a reporting period compared to the end of that period (note 17).

(u) Recognition of revenue

Revenue derived from non-regulated energy generation sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

Revenues related to utility electricity and natural gas sales and distribution are recorded based on metered consumptions by customers, which occur on a systematic basis throughout a month, rather than when the electricity or natural gas is delivered. At the end of each month, the electricity and natural gas delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled sales and revenues are based on the ratio of billable days versus unbilled days, amount of electricity or natural gas procured during that month, historical customer class usage patterns, weather, line loss, unaccounted-for gas and current tariffs.

Beginning in 2013, in accordance with the revenue decoupling mechanism approved by its regulator, Liberty Utilities (CalPeco Electric) LLC ("Calpeco Electric System ") is required to charge approved annual delivery revenues evenly over its fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers (note 7).

Water reclamation and distribution revenues are recorded when water is processed or delivered to customers. At the end of each month, the water delivered and waste water collected from the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled revenues are based on the ratio of billable days versus unbilled days, amount of water procured and collected during that month, historical customer class usage patterns and current tariffs.

Revenue is recorded net of sale taxes.

Interest from long-term investments is recorded as earned.

**1. Significant accounting policies (continued)**

(v) Foreign currency translation

The Company's reporting currency is the Canadian dollar.

The Company's US operations are determined to have the U.S. dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. The financial statements of these operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date while revenues and expenses are converted using average rates for the period. Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of other comprehensive income ("OCI") and are accumulated in a component of equity on the consolidated balance sheets and are not recorded in income unless there is a complete or substantially complete sale or liquidation of the investment.

(w) Income taxes

Income taxes are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is recorded against deferred tax assets to the extent that it is considered more likely than not that the deferred tax asset will not be realized. The effect on deferred assets and liabilities of a change in tax rates is recognized in earnings in the period that includes the date of enactment. Income tax credits are treated as a reduction to current income tax expense in the year the credit arises or future periods to the extent that realization of such benefit is more likely than not. Investment tax credits are recorded as an offset to the related long-lived asset. They are amortized over the estimated life of the asset as credits to income tax expense.

The organizational structure of APUC and its subsidiaries is complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there can be tax matters that have uncertain tax positions. The Company follows ASC 740-10 and recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

(x) Financial instruments and derivatives

Accounts receivable and notes receivable are measured at amortized cost and there is no liquid market for these investments. Long-term liabilities, convertible debentures, and other long-term liabilities are measured at amortized cost using the effective interest method, adjusted for the amortization or accretion of premiums or discounts.

Transaction costs that are directly attributable to the acquisition of financial assets are accounted for as part of the respective asset's carrying value at inception. Transaction costs for items classified as held-for-trading are expensed immediately. Transaction costs that are directly attributable to the issuance of financial liabilities, costs of arranging the Company's credit facility and costs considered as commitment fees paid to financial institutions are recorded in deferred financing costs. Deferred financing costs, premiums and discounts on long-term debt are amortized using the effective interest method while deferred financing costs relating to revolving credit facilities are amortized on a straight-line basis over the term of the facility.

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities in the consolidated balance sheets at their respective fair values. The fair value recognized on derivative instruments executed with the same counterparty under a master netting arrangement are presented on a gross basis on the consolidated balance sheet. The amounts that could net settle are not significant. The Company applies hedge accounting to financial instruments used to manage its foreign currency risk exposure and price risk exposure associated with sales of generated electricity.

1. **Significant accounting policies (continued)**

(x) Financial instruments and derivatives (continued)

For derivatives designated in a cash flow hedge relationship, the effective portion of the change in fair value is recognized as other comprehensive income. The ineffective portion is immediately recognized in earnings. The amount recognized in accumulated other comprehensive income is removed and included in earnings in the same period as the hedged cash flows affect earnings under the same line item in the statement of income as the hedged item. If the hedging instrument no longer meets the criteria for hedge accounting, expires or is sold, terminated, exercised, or the designation is revoked, then hedge accounting is discontinued prospectively. The amount recognized in accumulated other comprehensive income is transferred to the income statement in the same period that the hedged item affects profit or loss. If the forecast transaction is no longer expected to occur, then the balance in accumulated other comprehensive income is recognized immediately in earnings.

Foreign currency gain or loss on derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations, that are effective as a hedge are reported in the same manner as the translation adjustment (in other comprehensive income) related to the net investment. To the extent that the hedge is ineffective, such differences are recognized in earnings.

Calpeco Electric System and Liberty Utilities (Granite State Electric) Corp. ("Granite State Electric System") enter into Power Purchase Agreements ("PPA") for load serving requirements. These contracts meet the exemption for normal purchase and normal sales and as such, are not required to be recorded at fair value as derivatives and are accounted for on an accrual basis. Counterparties are evaluated on an on-going basis for non-performance risk to ensure it does not impact the conclusion with respect to this exemption.

(y) Fair value measurements

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principal or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1 inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

(z) Commitments and contingencies

Liabilities for loss contingencies arising from environmental remediation, claims, assessments, litigation, fines, and penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred.

**1. Significant accounting policies (continued)**

(aa) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment and intangible assets, the annual impairment testing of reporting units containing goodwill, the recoverability of notes receivable and long-term investments, the recoverability of deferred tax assets, assessments of unbilled revenue, pension and OPEB obligations, timing effect of regulated assets and liabilities, contingencies related to environmental matters, and the fair value of financial instruments, derivatives and share-based compensation. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

**2. Recently issued accounting pronouncements**

(a) Recently adopted accounting pronouncements

The FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities and ASU 2013-01 Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. These newly issued accounting standards require an entity to disclose both gross and net information about financial instruments and transactions eligible for offset in the balance sheet including financial instruments and transactions executed under a master netting or similar arrangement. The standards were issued to enable users of the financial statements to understand the effects or potential effects of such arrangements on an entity's financial position. The adoption of these standards as at January 1, 2013 did not have a material impact on the Company's consolidated financial statements.

The FASB issued ASU 2013-02, Comprehensive Income (Topic 220): This newly issued accounting standard requires an entity to provide certain information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes to the financial statements, the effect of, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. Other than the additional disclosure (note 16), the adoption of this standard did not have a material impact on the Company's consolidated financial statements.

## 2. Recently issued accounting pronouncements (continued)

(b) Recent accounting guidance not yet adopted

The FASB issued ASU 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This newly issued accounting standard requires an entity to present an unrecognized tax benefit, or a portion of an unrecognized tax benefit as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except in some specific situations. This ASU is required to be applied prospectively for fiscal years, and interim periods beginning after December 15, 2013. The adoption of this standard is not expected to have an impact the Company's financial position or results of operations.

The FASB issued ASU 2013-10, Derivatives and Hedging (Topic 815): Inclusion of the Fed Funds Effective Swap Rate (or Overnight Index Swap Rate) as a Benchmark Interest Rate for Hedge Accounting Purposes. This newly issued accounting standard permit the Fed Funds Effective Swap Rate (OIS) to be used as a U.S. benchmark interest rate for hedge accounting purposes under Topic 815, in addition to interest rates on direct Treasury obligations of the U.S. government and the London Interbank Offered Rate. The amendments also remove the restriction on using different benchmark rates for similar hedges. This ASU is required to be applied prospectively for qualifying new or re-designated hedging relationships entered into on or after July 17, 2013. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

The FASB issued ASU 2013-04, Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation Is Fixed at the Reporting Date. This newly issued accounting standard provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. This ASU is required to be applied retrospectively for fiscal years, and interim periods within those years beginning after December 15, 2013. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

## 3. Business acquisitions and development projects

(a) Agreement to acquire the noncontrolling interest in U.S. Wind farms

On November 28, 2013, APCo entered into an agreement to acquire the 40% interest in Wind Portfolio SponsorCo, LLC ("SponsorCo") from Gamesa Corporación Tecnológica, S.A. for approximately U.S. $117,000. SponsorCo indirectly holds the interests in Sandy Ridge, Senate and Minonk Wind acquired in 2012. The transaction will result in the elimination of the noncontrolling interest in respect of the Class B partnership units of SponsorCo including its portion of Accumulated other comprehensive income and resulting tax effect. Any difference with the consideration paid will be recorded as Additional paid-in capital.

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 3. Business acquisitions and development projects (continued)

(b) Acquisition of New England Gas System

On December 20, 2013, Liberty Utilities acquired certain regulated natural gas distribution utility assets (the "New England Gas System") located in the State of Massachusetts. Total purchase price for the New England Gas System, net of the debt assumed, is approximately U.S. $59,100, subject to certain working capital and other closing adjustments.

The following table summarizes the preliminary determination of the fair value of the assets acquired and liabilities assumed at the acquisition date:

| | | |
|---|---|---|
| Cash | $ | 76 |
| Working capital | | 8,175 |
| Property, plant and equipment | | 84,636 |
| Regulatory assets | | 47,644 |
| Other assets | | 1,197 |
| Long term debt (including current portion) | | (25,836) |
| Regulatory liabilities | | (15,969) |
| Pension and OPEB | | (25,360) |
| Environmental obligation | | (10,225) |
| Deferred income tax liability, net | | (1,217) |
| Total net assets acquired | $ | 63,121 |

Due to the timing of the acquisition, the Company has not completed the fair value measurements of the assets acquired and liabilities assumed. The determination of the fair value has been based upon management's preliminary estimates of final closing adjustments, certain estimates and assumptions with respect to the fair values of the assets acquired and liabilities assumed. The Company will continue to review information and perform further analysis prior to finalizing the fair value of the consideration paid and the fair value of the assets acquired and liabilities assumed. The actual fair values of the assets acquired and liabilities assumed may differ from the amounts above.

Property, plant and equipment are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight line method. The weighted average useful life of New England Gas System assets is 55 years.

All costs related to the acquisition have been expensed through the consolidated statements of operations.

New England Gas System contributed revenue of $3,582 and net earnings of $1,153 to the Company's consolidated financial results for 2013. Pro forma financial information is disclosed in note 3(f).

*(in thousands of Canadian dollars except as noted and amounts per share)*

**3. Business acquisitions and development projects (continued)**

(c) Acquisition of Peach State Gas System

On April 1, 2013 Liberty Utilities acquired certain regulated natural gas distribution utility assets (the "Peach State Gas System") located in the State of Georgia. The total purchase price for the Peach State Gas System adjusted for certain working capital and other closing adjustments, is approximately $155,578 (U.S. $153,000).

The following table summarizes the preliminary determination of the fair value of the assets acquired and liabilities assumed at the acquisition date:

| | | |
|---|---|---|
| Working capital | $ | 9,605 |
| Property, plant and equipment | | 141,983 |
| Goodwill | | 12,226 |
| Deferred income tax asset, net | | 1,992 |
| Derivative asset | | 231 |
| Regulatory liabilities | | (3,807) |
| Other liabilities | | (1,853) |
| Pension and OPEB | | (4,615) |
| Derivative liabilities | | (184) |
| Total net assets acquired | $ | 155,578 |

The Company has not completed the fair value measurement of the assets acquired and liabilities assumed, particularly that of certain executory contracts. The determination of the fair value has been based upon management's preliminary estimates and assumptions with respect to the fair values of the assets acquired and liabilities assumed. The Company will continue to review information and perform further analysis prior to finalizing the fair value of the consideration paid and the fair value of the assets acquired and liabilities assumed. The actual fair values of the assets acquired and liabilities assumed may differ from the amounts above.

Goodwill represents the excess of the fair value of the consideration paid over the fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include expected future cash flows, potential operational synergies, the utilization of technology, and cost savings opportunities in the delivery of certain shared administrative and other services. The goodwill related to the Peach State Gas System has been reported under the Liberty Utilities (East) segment.

Property, plant and equipment are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight line method. The weighted average useful life of the Peach State Gas System assets is 55 years.

All costs related to the acquisition have been expensed through the consolidated statements of operations.

Peach State Gas System contributed revenue of $37,889 and net earnings of $5,692 to the Company's consolidated financial results for 2013. Pro forma financial information is disclosed in note 3(f).

*(in thousands of Canadian dollars except as noted and amounts per share)*

**3. Business acquisitions and development projects (continued)**

(d) Acquisition of Pine Bluff Water System

On February 1, 2013, Liberty Utilities acquired United Water Arkansas Inc. a regulated water distribution utility (the "Pine Bluff Water System") located in Pine Bluff, Arkansas. Total purchase price for the Pine Bluff Water System, adjusted for certain working capital and other closing adjustments, is approximately $27,858 (U.S. $27,934).

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date. The determination of the fair value of assets and liabilities acquired is based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed.

| | | |
|---|---|---|
| Cash | $ | 8 |
| Working capital | | 766 |
| Property, plant and equipment | | 28,371 |
| Regulatory assets | | 957 |
| Goodwill | | 5,034 |
| Other liabilities | | (169) |
| Regulatory liabilities | | (135) |
| Pension and OPEB | | (4,277) |
| Deferred income tax liability, net | | (2,697) |
| Total net assets acquired | $ | 27,858 |

Goodwill represents the excess of the fair value of the consideration paid over the fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include expected future cash flows, potential operational synergies, the utilization of technology, and cost savings opportunities in the delivery of certain shared administrative and other services. The goodwill related to the Pine Bluff Water System has been reported under the Liberty Utilities (Central) segment.

Property, plant and equipment are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight line method. The weighted average useful life of the Pine Bluff Water System assets is 40 years.

All costs related to the acquisition have been expensed through the consolidated statements of operations.

Pine Bluff Water System contributed revenue of $8,708 and net earnings of $1,894 to the Company's consolidated financial results for 2013. The disclosure of pro forma revenue and earnings has been deemed immaterial.

*(in thousands of Canadian dollars except as noted and amounts per share)*

**3. Business acquisitions and development projects (continued)**

(e) Acquisition of Shady Oaks Wind Facility

Effective January 1, 2013, APCo acquired the 109.5 megawatt ("MW") Shady Oaks wind powered generating facility ("Shady Oaks Wind Facility") by assuming the existing long-term debt of approximately U.S. $150,000 for no additional cash. The purchase agreement provides for final purchase price adjustments based on working capital at the acquisition date, energy generated by the project and basis differences between the relevant node and hub prices.

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date. The determination of the fair value is based upon management's estimates and assumptions with respect to the fair value of the assets acquired and liabilities assumed.

| | |
|---|---|
| Cash | $ 4,682 |
| Working capital | (846) |
| Property, plant and equipment | 144,243 |
| Deferred tax asset | 2,519 |
| Long term debt (including current portion) | (149,235) |
| Asset retirement obligation | (1,363) |
| Total net assets acquired | $ — |

Property, plant and equipment are amortized on a straight line basis over the lives of the assets, which have a weighted average useful life of 37 years.

Shady Oaks Wind Facility earns revenue from the sale of electricity and renewable energy credits and from capacity payments. Shady Oaks Wind Facility recognizes revenue from the sale of electricity and renewable energy credits ("RECs") based upon the output delivered at rates specified under a long-term power purchase agreement with Commonwealth Edison Company ("ComEd"). Shady Oaks Wind Facility has contracted to sell approximately 310,000 MW hours of electricity (and associated RECs) to ComEd each year, commencing June 1, 2012, under this long-term power purchase agreement. On March 29, 2013, ComEd issued curtailment notice reducing the annual contract quantity for the delivery year from June 1, 2013 to May 31, 2014 to 252,617 MW hours. Electricity and associated renewable energy credits not sold to ComEd will be sold into wholesale electric markets.

Shady Oaks Wind Facility contributed revenue of $17,472 and net earnings of $3,297 to APUC's consolidated financial results for 2013. The disclosure of pro forma revenue and earnings has been deemed impracticable as Shady Oaks Wind Facility being a newly constructed wind power generation facility only achieved commercial operations in the second half of 2012 and therefore had little operations prior to the acquisition by APCo.

All costs related to the acquisition have been expensed in the consolidated statements of operations.

*(in thousands of Canadian dollars except as noted and amounts per share)*

**3. Business acquisitions and development projects (continued)**

(f) Pro forma information

The supplemental pro forma financial information below was prepared using the acquisition method of accounting and is based on the historical financial information of APUC, New England Gas System and Peach State Gas System reflecting results of operations for 2013 and 2012 on a comparative basis as though the aforementioned companies were combined as of January 1, 2012. The acquiree's pre-acquisition results have been added to APUC's historical results, and the totals have been adjusted for the pro forma effects of acquisition-related costs, interest expense related to the financing of the business combinations, and related income taxes.

| Pro forma | 2013 | 2012 |
|---|---|---|
| Total revenue from continuing operations | $ 760,394 | $ 464,182 |
| Net earnings from continuing operations | 59,698 | 28,103 |
| Basic net earnings from continuing operations per share | 0.32 | 0.13 |
| Diluted net earnings from continuing operations per share | 0.32 | 0.13 |

The above unaudited pro forma financial information is presented for informational purposes only and does not purport to represent what the results would have been had the acquisition closed on the date assumed, nor is it necessarily indicative of the results that may be expected in future periods.

(g) Acquisition of New Hampshire Electric and Gas Systems

In 2013, the Company received additional information which was used to refine the estimates for fair value of assets acquired and liabilities assumed on July 3, 2012 for the New Hampshire electric and gas utilities. The carrying value of those assets and liabilities were retrospectively adjusted to the amounts detailed in the table below. As a result, the total consideration was reduced by $9,216, working capital acquired was reduced by $9,869 and goodwill was increased by $957.

| | Granite State | EnergyNorth | Total |
|---|---|---|---|
| Cash | $ 395 | $ — | $ 395 |
| Restricted cash | 3,252 | — | 3,252 |
| Working capital | 1,916 | 15,420 | 17,336 |
| Property, plant and equipment | 86,935 | 256,305 | 343,240 |
| Regulatory assets | 31,683 | 87,126 | 118,809 |
| Deferred financing | 31 | — | 31 |
| Other assets | — | 83 | 83 |
| Goodwill | — | 28,537 | 28,537 |
| Customer deposits | (661) | (962) | (1,623) |
| Long-term debt | (15,188) | — | (15,188) |
| Other long-term liabilities | (1,468) | (3,287) | (4,755) |
| Advances in aid of construction | — | (86) | (86) |
| Derivative liabilities | — | (2,598) | (2,598) |
| Regulatory liabilities | (5,533) | (27,456) | (32,989) |
| Pension and OPEB | (19,108) | (29,197) | (48,305) |
| Environmental obligation | — | (54,431) | (54,431) |
| Deferred income tax liabilities, net | — | (61,484) | (61,484) |
| Total net assets acquired | $ 82,254 | $ 207,970 | $ 290,224 |

*(in thousands of Canadian dollars except as noted and amounts per share)*

**3. Business acquisitions and development projects (continued)**

(h) Acquisition of solar energy project

On January 4, 2012, APCo acquired rights to develop a 10 MWac solar project located near Cornwall, Ontario which has been granted a Feed-in-Tariff contract by the Ontario Power Authority for a 20 year term at a rate of $443/MWh. The consideration for the development rights is $4,500 plus additional contingent consideration of $3,500 based on achieving certain construction milestones. As at December 31, 2013, the Company has paid a total of $3,000 based on achieved milestones. The transaction has been recorded as a purchase of intangible assets. In addition, as at December 31, 2013, the Company has invested $33,259 in the development and construction of the solar energy project which is recorded as property, plant and equipment.

(i) Acquisition of noncontrolling interest in Calpeco Electric System

On December 21, 2012, APUC acquired the 49.999% interest in Calpeco Electric System from Emera Inc. (“Emera”) that it did not previously hold for $38,756 which was funded by the proceeds of common share subscription receipts (note 15(a)(ii)). The impact on the Company’s consolidated balance sheet was as follows:

| | | 2012 |
|---|---|---|
| Elimination of noncontrolling interest (net of intercompany balance of $1,297 with Emera) | $ | 33,726 |
| Noncontrolling interest portion of currency translation adjustment transferred to AOCI | | 1,397 |
| Accumulated deficit | | 3,633 |
| Exercise of subscription receipts | $ | 38,756 |

During the third quarter of 2013, the Company completed the tax filings in connection with the acquisition of Emera’s noncontrolling interest in Calpeco Electric System and identified an adjustment to the deferred tax balance. The $3,649 deferred tax adjustment identified has been recorded in the current period as an adjustment to accumulated deficit consistent with the accounting for the acquisition of the noncontrolling interest.

**4. Accounts receivable**

Accounts receivable as of December 31, 2013 includes unbilled revenue of $45,274 (December 31, 2012 - $22,658) from the Company's regulated utilities. Accounts receivable as at December 31, 2013 is presented net of allowance for doubtful accounts of $8,461 (December 31, 2012 - $4,360).

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 5. Property, plant and equipment

Property, plant and equipment consist of the following:

**2013**

| | Cost | Accumulated depreciation | Net book value |
|---|---|---|---|
| Generation | | | |
| Renewable | $ 1,438,229 | $ 166,175 | $ 1,272,054 |
| Thermal | 116,975 | 43,596 | 73,379 |
| Distribution | | | |
| Water & wastewater | 303,410 | 63,807 | 239,603 |
| Electricity | 277,679 | 16,782 | 260,897 |
| Gas | 690,034 | 19,758 | 670,276 |
| Land | 8,266 | — | 8,266 |
| Equipment | 71,292 | 25,111 | 46,181 |
| Construction in progress | 138,048 | — | 138,048 |
| | $ 3,043,933 | $ 335,229 | $ 2,708,704 |

**2012**

| | Cost | Accumulated depreciation | Net book value |
|---|---|---|---|
| Generation | | | |
| Renewable | $ 1,132,631 | $ 78,772 | $ 1,053,859 |
| Thermal | 208,183 | 78,336 | 129,847 |
| Distribution | | | |
| Water & wastewater | 240,376 | 52,162 | 188,214 |
| Electricity | 259,461 | 7,765 | 251,696 |
| Gas | 352,491 | 5,940 | 346,551 |
| Land | 7,318 | — | 7,318 |
| Equipment | 67,740 | 22,712 | 45,028 |
| Construction in progress | 63,765 | — | 63,765 |
| | $ 2,331,965 | $ 245,687 | $ 2,086,278 |

Renewable generation assets include cost of $86,774 (2012 - $88,198) and accumulated depreciation of $31,739 (2012 - $29,584) related to facilities under capital lease or owned by consolidated variable interest entities. Depreciation expense of facilities under capital lease was $2,155 (2012 - $2,244).

Investments tax credits, government grants and contributions received in aid of construction of $3,098 (2012 - $6,341) have been credited to the cost of the distribution assets. Water and wastewater distribution assets include expansion costs of $1,000 on which the Company does not currently earn a return.

Subsequent to year-end, on January 3, 2014, APUC, through wholly owned subsidiaries, acquired a new office facility in Oakville, Ontario. The purchase price for the building was $46,800 and was financed through APUC's credit facility.

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 6. Intangible assets and goodwill

Intangible assets consist of the following:

**2013**

| | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| Power sales contracts | $ 61,430 | $ 28,987 | $ 32,443 |
| Customer relationships | 28,512 | 6,539 | 21,973 |
| | $ 89,942 | $ 35,526 | $ 54,416 |

**2012**

| | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| Power sales contracts | $ 60,435 | $ 24,881 | $ 35,554 |
| Customer relationships | 26,674 | 5,447 | 21,227 |
| | $ 87,109 | $ 30,328 | $ 56,781 |

Estimated amortization expense for intangibles for the next three years is $4,560 each year, $2,810 in year four and $2,470 in year five.

Changes in goodwill per operating segment are as follows:

| | Liberty Utilities | | | |
|---|---|---|---|---|
| | Central | West | East | Total |
| Balance, January 1, 2012 | $ 192 | $ 9,517 | $ — | $ 9,709 |
| Business acquisitions | 25,257 | — | 26,527 | 51,784 |
| Foreign exchange | (357) | (251) | 574 | (34) |
| Balance, December 31, 2012 | $ 25,092 | $ 9,266 | $ 27,101 | $ 61,459 |
| Business acquisitions | 5,034 | — | 12,226 | 17,260 |
| Adjustments | (209) | — | 957 | 748 |
| Foreign exchange | 2,056 | 640 | 2,484 | 5,180 |
| Balance, December 31, 2013 | $ 31,973 | $ 9,906 | $ 42,768 | $ 84,647 |

## 7. Regulatory matters

The Company's regulated utility operating companies are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting policies, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The Company`s regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate setting process.

On November 29, 2012, the Company's Calpeco Electric System regulator approved an All Parties General Rate Case Settlement. As an element of the decision, a revenue decoupling mechanism and a vegetation management memorandum account were agreed upon. The revenue decoupling mechanism will isolate base revenues from fluctuations caused by weather and economic factors. The vegetation management memorandum account allows for the tracking and pass through of vegetation management expenses to customers, one of the largest expenses of the utility.

*(in thousands of Canadian dollars except as noted and amounts per share)*

**7. Regulatory matters (continued)**

At any given time, Liberty Utilities can have several regulatory proceedings underway. The financial effects of these proceedings are reflected in the financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period.

Regulatory assets and liabilities consist of the following:

| | 2013 | 2012 |
|---|---|---|
| **Regulatory assets** | | |
| Environmental costs (a) | $ 80,438 | $ 59,789 |
| Pension and post-employment benefits (b) | 64,997 | 47,838 |
| Storm costs (c) | 5,437 | 6,726 |
| Energy costs adjustment (d) | 20,495 | 7,962 |
| Rate case costs (e) | 3,119 | 2,398 |
| Vegetation management | 2,297 | 2,082 |
| Debt premium (f) | 4,504 | — |
| Asset retirement obligation (g) | 1,468 | 1,095 |
| Tax related | 2,995 | 1,160 |
| Other | 4,598 | 5,342 |
| Total regulatory assets | $ 190,348 | $ 134,392 |
| Less current regulatory assets | (34,643) | (10,644) |
| Non-current regulatory assets | $ 155,705 | $ 123,748 |
| **Regulatory liabilities** | | |
| Cost of removal (h) | $ 68,698 | $ 58,852 |
| Rate-base offset (i) | 25,082 | 15,541 |
| Energy costs adjustment (d) | 17,394 | 13,891 |
| Pension and post-employment benefits (b) | 6,770 | 1,127 |
| Rate adjustment mechanism | 1,681 | — |
| Tax related | 133 | — |
| Other | 3,531 | 1,265 |
| Total regulatory liabilities | $ 123,289 | $ 90,676 |
| Less current regulatory liabilities | (21,632) | (8,626) |
| Non-current regulatory liabilities | $ 101,657 | $ 82,050 |

(a) Environmental remediation costs recovery: Actual expenditures incurred for the cleanup of certain former gas manufacturing facilities (see note 23 (a) (ii)) are recovered through rates over a period of 7 years.

(b) Pension and post-employment benefits: As part of a business acquisition, the Regulators authorized a regulatory asset or liability being set up for the amounts of pension and post-retirement benefits that have not yet been recognized in net periodic cost and were presented as accumulated comprehensive income prior to the acquisition. A net portion of $12,213 is currently recovered through rates over the future services years of the employees. The balance of $46,014 relates to recent acquisitions and was authorized for recognition as an asset by the Regulator. Recovery of $23,013 through rates is expected to start in the second quarter of 2014. The remaining $23,001 is anticipated to be approved in a final rate order in 2015.

(c) Storm costs: Incurred repair costs resulting from certain storms, which are expected to be recovered through rates.

*(in thousands of Canadian dollars except as noted and amounts per share)*

**7. Regulatory matters (continued)**

(d) Energy cost adjustment: The revenue of the electric and natural gas utilities include a component which is designed to recover the cost of electricity or natural gas through rates charged to customers. Under deferred energy accounting, to the extent actual natural gas and purchased power costs differ from natural gas and purchased power costs recoverable through current rates that difference is not recorded on the consolidated statements of operations but rather is deferred and recorded as a regulatory asset or liability on the balance sheet. These differences are reflected in adjustments to rates and recorded as an adjustment to cost of natural gas or electricity in future time periods, subject to regulatory review. Derivatives are often utilized to manage the price risk associated with natural gas purchasing activities in accordance with the expectations of state regulators. The gains and losses associated with these derivatives are recoverable through the energy cost adjustment (note 26(b)(i)).

(e) Rate case costs: The costs to file, prosecute and defend rate case applications are referred to as rate case costs. These costs are capitalized and amortized over the period of rate recovery granted by the Regulator.

(f) Debt premium: The value of debt assumed in the acquisition of New England Gas System has been recorded at fair value in accordance with ASC 805 Business Combinations. The Massachusetts regulator allows for recovery of interest at the coupon rate of the debt and a regulatory asset has been recorded for the difference between the fair value and face value of the debt.

(g) Asset retirement obligation: Asset retirement obligations incurred by the utilities are expected to be recovered through rates.

(h) Cost of removal: The regulatory liability for cost of removal represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire the utility plant.

(i) Rate-base offset: The Regulator imposed a rate base offset that would reduce the revenue requirement at future rate proceedings. The rate base offset declines on a straight-line basis over a period of ten years.

The Company records carrying charges on the regulatory balances related to energy costs adjustment and storm costs. As recovery of regulatory assets is subject to regulatory approval, if there were any changes in regulatory positions that indicate recovery is not probable, the related cost would be charged to income in the period of such determination.

**8. Long-term investments and notes receivable**

Long-term investments and notes receivable consist of the following:

| | 2013 | 2012 |
|---|---|---|
| **Long-term investments** | | |
| 32.4% of Class B non-voting shares of Kirkland Lake Power Corp. | $ 4,851 | $ 4,926 |
| 25% of Class B non-voting shares of Cochrane Power Corporation | 3,772 | 4,669 |
| 45% interest in the Algonquin Power (Rattle Brook) Partnership (b) | — | 3,884 |
| 50% interest in the Valley Power Partnership | 1,718 | 1,767 |
| Other | 325 | 180 |
| Total long-term investments | $ 10,666 | $ 15,426 |
| **Notes Receivable** | | |
| Red Lily Senior loan, interest at 6.31% (a) | $ 11,588 | $ 11,588 |
| Red Lily Subordinated loan, interest at 12.5% (a) | 6,565 | 6,565 |
| Chapais Énergie, Société en Commandite interest at 10.789% and 4.91%, respectively | 1,928 | 2,448 |
| Silverleaf resorts loan, interest at 15.48% maturing July 2020 | 2,149 | 2,010 |
| Other | 448 | 146 |
| | 22,678 | 22,757 |
| Less: current portion | (598) | (537) |
| Total long-term notes receivable | $ 22,080 | $ 22,220 |
| Total long-term investments and notes receivable | $ 32,746 | $ 37,646 |

*(in thousands of Canadian dollars except as noted and amounts per share)*

**8. Long-term investments and notes receivable (continued)**

The above notes are secured by the underlying assets of the respective facilities.

(a) Red Lily I

The Red Lily I Partnership ("Partnership") is owned by an independent investor. The Company provides operation and supervision services to the Red Lily I project, a 26.4 megawatt wind energy facility located in south-eastern Saskatchewan.

The Company's investment in Red Lily I is in the form of participation in a portion of the senior debt facility, and a subordinated debt facility to the Partnership. In 2011, APUC advanced $13,000 under a senior debt facility to the Partnership and received a pre-payment of $1,412 in 2012. Another third party lender has also advanced $31,000 of senior debt to the Partnership. The Company's senior loan to the Partnership earns interest at the rate of 6.31% and will mature in 2016. Both tranches of senior debt are secured by substantially all the assets of the Partnership on a pari passu basis.

The subordinated loan earns an interest rate of 12.5%, the principal matures in 2036 but is repayable by the Partnership in whole or in part at any time after 2016, without a pre-payment premium. The subordinated loan is secured by substantially all the assets of the Partnership but is subordinated to the senior debt.

A second tranche of subordinated loan for an amount equal to the amounts outstanding on Tranche 2 of the senior debt but no greater than $17,000 will be advanced in 2016 by the Company. The proceeds from this additional subordinated debt are required to be used to repay Tranche 2 of the Partnership's senior debt, including APUC's portion.

In connection with the subordinated debt facility, the Company has been granted an option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated loan of up to $19,500, exercisable for a period of 90 days commencing in 2016. The fair value of the conversion option as at December 31, 2013 and 2012 was determined to be negligible.

(b) Algonquin Power (Rattle Brook) Partnership

The Algonquin Power (Rattle Brook) Partnership was sold to related parties effective December 31, 2013 (see note 21).

**9. Long-term liabilities**

Long term liabilities consist of the following:

| | 2013 | 2012 |
|---|---|---|
| **APCo** | | |
| Revolving $200,000 credit facility, revolving line of credit interest rate is equal to bankers' acceptance or LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is BA or LIBOR plus 1.75%, maturing November 16, 2015. | $ 124,570 | $ 27,074 |
| Senior Unsecured Notes: $150,000 senior unsecured notes, bearing an interest rate of 4.82% maturing February 15, 2021. The notes are interest only, payable semi-annually in arrears. | 149,920 | 149,910 |
| Senior Unsecured Notes: $135,000 senior unsecured notes, bearing an interest rate of 5.50% maturing July 25, 2018. The notes are interest only, payable semi-annually in arrears. | 134,837 | 134,807 |
| Senior Debt - Shady Oaks Wind Facility: U.S. $122,000 Chinese Development Bank Corporation loan facility, bearing an interest rate of 6 month LIBOR plus 280 basis points, maturing June 30, 2026. The facility has principal and interest payments, payable semi-annually in arrears. | 129,759 | — |
| Senior Debt - Long Sault Hydro Facility: Bonds bearing an interest rate of 10.21% maturing December 31,2027. The bonds have interest and principal payments, monthly in arrears. | 37,143 | 38,136 |

*(in thousands of Canadian dollars except as noted and amounts per share)*

| | 2013 | 2012 |
|---|---|---|
| Senior Debt - Sanger Thermal Facility:<br>U.S. $19,200 California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bond Series 1990A, bearing an effective interest rate determined by the remarketing agent, maturing September 15, 2020. The bond has interest only payments, payable monthly in arrears. The effective interest rate in 2013 was 1.72% (2012 – 2.29%). | 20,421 | 19,102 |
| Senior Debt - Chuteford Hydro Facility:<br>Bonds bearing an interest rate of 11.6%, maturing April 1, 2020. The bond has principal and interest payments, payable monthly in arrears. | 3,417 | 3,763 |
| **Liberty Utilities** | | |
| Revolving U.S. $200,000 credit facility, revolving line of credit interest rate is equal to LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 1.25%, maturing September 30, 2018. | 85,620 | 27,360 |
| Senior Unsecured Notes: | | |
| Liberty Utilities Co.:<br>U.S. $50,000, bearing an interest rate of 3.51%, maturing July 31, 2017; U.S. $115,000, bearing an interest rate of 4.49%, maturing August 1, 2022; U.S. $60,000, bearing an interest rate of 4.89%, maturing July 30, 2027; U.S. $15,000, bearing an interest rate of 4.14%, maturing March 13, 2023; U.S. $25,000, bearing an interest rate of 3.23%, maturing July 31, 2020; U.S. $75,000, bearing an interest rate of 3.86%, maturing July 31, 2023; and U.S. $25,000, bearing an interest rate of 4.26%, maturing July 31, 2028. The notes interest only payments, payable semi-annually. | 388,214 | 223,852 |
| Calpeco Electric System:<br>U.S. $45,000 senior unsecured notes bearing an interest rate of 5.19%, maturing December 29, 2020 and U.S. $25,000 senior unsecured notes bearing an interest rate of 5.59%, maturing December 29, 2025. The notes are interest only payments, payable semi-annually in arrears. | 74,452 | 69,643 |
| Liberty Water Co:<br>U.S. $50,000 senior unsecured notes bearing an interest rate of 5.60% maturing December 22, 2020. The note has interest only payments, payable semi-annually in arrears, until June 20, 2016 after which the note will bear semi-annual interest payments thereafter. | 53,180 | 49,745 |
| New England Gas System:<br>First mortgage bonds, U.S. $6,500, bearing an interest rate of 9.44%, maturing February 15, 2020; U.S. $7,000, bearing an interest rate of 7.99%, maturing September 15, 2026; U.S. $6,000, bearing an interest rate of 7.24%, maturing December 15, 2027. The bonds have interest only payments. | 25,244 | — |
| Granite State Electric System:<br>Senior unsecured notes, U.S. $5,000, bearing an interest rate of 7.37%, maturing November 1, 2023; U.S. $5,000, bearing an interest rate of 7.94%, maturing July 1, 2025; and, U.S. $5,000, bearing an interest rate of 7.30%, maturing June 15, 2028. The notes have interest only payments, payable semi-annually. | 15,954 | 14,924 |
| LPSCo Water System:<br>1999 and 2001 IDA Bonds bearing interest rates of 5.95% and 6.75% and maturing October 1, 2023 and October 1, 2031 respectively. The bonds have principal and interest payments, payable monthly in arrears. | 11,668 | 11,269 |
| Bella Vista Water System:<br>Water Infrastructure Financing Authority of Arizona loans bearing interest rates of 6.26% and 6.10% , and maturing March 1, 2020 and December 1, 2017, respectively. The loans have principal and interest payments, payable monthly and quarterly in arrears. | 1,189 | 1,241 |
| | $ 1,255,588 | $ 770,826 |
| Less: current portion | (8,339) | (1,768) |
| | $ 1,247,249 | $ 769,058 |

**9. Long-term liabilities (continued)**

Certain long-term debt issued at a subsidiary level relating to a specific operating facility is secured by the respective facility with no other recourse to APUC, APCo or Liberty Utilities. The loans have certain financial covenants, which must be maintained on a quarterly basis. Noncompliance with the covenants could restrict cash distributions/dividends to APUC, APCo and Liberty Utilities from the specific facilities.

**APCo**

Subsequent to year-end on January 17, 2014, APCo issued $200,000 senior unsecured debentures bearing interest at 4.65% and with a maturity date of February 15, 2022. The debentures were sold at a price of $99.864 per $100.00 principal amount. Interest payments will be payable on February 15 and August 15 each year, commencing on February 15, 2014. APCo incurred deferred financing costs of $940, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Concurrent with the offering, APCo entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars. APCo designated the entire notional amount of the cross currency fixed for fixed interest rate swap and related short-term USD payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in APCo's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the USD accruals that are designated as, and are effective as, an economic hedge of the net investment in a foreign operation will be reported in the same manner as the translation adjustment (in other comprehensive income) related to the net investment.

Effective January 1, 2013, concurrent with the acquisition of Shady Oaks Wind Facility (note 3(e)), APCo assumed existing long-term debt of approximately U.S. $150,000. Principal of U.S. $28,000 was repaid during the year and another portion of U.S. $40,000 was paid subsequent to year-end on February 10, 2014 leaving a balance of U.S. $82,000 outstanding at that date. The semi-annual principal repayment schedule for the following 12.5 years ranges from U.S., $3,000 to U.S. $6,000 with a final repayment in 2026. This debt may be repaid in whole or in part at any time without penalty.

On December 3, 2012, APCo issued $150,000 senior unsecured debentures bearing interest at 4.82% and with a maturity date of February 15, 2021. The debentures were sold at a price of $99.94 per $100.00 principal amount. Interest payments are payable on February 15 and August 15 each year. APCo incurred deferred financing costs of $1,057, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Concurrent with the offering, APCo entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars (note 26(b)(iii)).

In 2012, APCo increased the maximum availability under its senior credit facility from $120,000 to $200,000 to meet future working capital needs. In addition, the bank syndicate agreed to release its security previously held over certain APCo entities, such that the facility is now fully unsecured. The facility has a maturity date of November 16, 2015.

**Liberty Utilities**

On December 20, 2013, in connection with the acquisition of New England Gas System, Liberty Utilities assumed first mortgage bonds of U.S. $6,000, bearing an interest rate of 7.24%, maturing December 15, 2027; U.S. $7,000, bearing an interest rate of 7.99%, maturing September 15, 2026; and, U.S. $6,500, bearing an interest rate of 9.44%, maturing Feb 15, 2020.

On September 30, 2013, Liberty Utilities increased the maximum availability under its revolving credit facility from U.S. $100,000 to $200,000 to meet future working capital requirements and allow for greater financial flexibility. The facility has a maturity date of September 30, 2018.

On July 31, 2013, Liberty Utilities issued U.S. $125,000 of senior unsecured notes through a private placement in three tranches: U.S. $25,000, bearing an interest rate of 3.23%, maturing July 31, 2020; U.S. $75,000, bearing an interest rate of 3.86%, maturing July 31, 2023; and, U.S. $25,000, bearing an interest rate of 4.26%, maturing July 31, 2028. The proceeds from the private placement financing were used to fund a portion of the acquisition of the Peach State Gas System (note 3(c)).

On March 14, 2013 Liberty Utilities issued U.S. $15,000 of senior unsecured notes through a private placement in connection with the acquisition of the Pine Bluff Water System (note 3(d)). The notes bear interest at 4.14% and mature March 13, 2023.

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 9. Long-term liabilities (continued)

### Liberty Utilities (continued)

In July 2012, Liberty Utilities issued U.S. $225,000 of senior unsecured notes through a private placement in three tranches: U.S. $50,000, bearing an interest rate of 3.51%, maturing July 31, 2017; U.S. $115,000, bearing an interest rate of 4.49%, maturing August 1, 2022; and, U.S. $60,000, bearing an interest rate of 4.89%, maturing July 30, 2027. The notes are interest only, payable semi-annually. Liberty Utilities incurred deferred financing costs of $2,663, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Liberty Utilities used the proceeds of the private placement financing to fund a portion of the acquisition of the New Hampshire Electric and Gas Systems and Midwest Gas System.

On July 3, 2012, in connection with the acquisition of Granite State Electric System, Liberty Utilities assumed senior unsecured long-term notes of U.S. $5,000, bearing an interest rate of 7.37%, maturing November 1, 2023; U.S. $5,000, bearing an interest rate of 7.94%, maturing July 1, 2025; and, U.S. $5,000, bearing an interest rate of 7.30%, maturing June 15, 2028.

### APUC

On November 19, 2013, APUC increased the maximum availability under its revolving credit facility from U.S. $30,000 to $65,000. The credit facility will be used for general corporate purposes and has a maturity date of November 19, 2016. As at December 31, 2013 and 2012, no amounts were outstanding under this facility.

As of December 31, 2013, the Company had accrued $14,057 in interest expense (2012 - $4,482). Interest paid on the long-term liabilities in 2013 was $49,746 (2012 - $20,671).

Principal payments due in the next five years and thereafter are:

| | 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| APCo | $ 7,864 | $ 132,508 | $ 8,212 | $ 10,540 | $ 10,767 | $ 430,176 | $ 600,067 |
| Liberty Utilities | 475 | 504 | 5,852 | 59,075 | 91,524 | 498,091 | 655,521 |
| Total | $ 8,339 | $ 133,012 | $ 14,064 | $ 69,615 | $ 102,291 | $ 928,267 | $1,255,588 |

## 10. Convertible debentures

| | Series 2A | Series 3 | Total |
|---|---|---|---|
| Maturity date | 2016 November 30 | 2017 September 30 | |
| Interest rate | 6.35% | 7.00% | |
| Conversion price per share | $ 6.00 | $ 4.20 | |
| Carrying value at January 1, 2012 | $ 59,726 | $ 62,571 | $ 122,297 |
| Conversion to common shares (note 15(a)(i)), net of costs | (59,950) | (61,611) | (121,561) |
| Amortization and accretion | 224 | — | 224 |
| Carrying amount at December 31, 2012 | $ — | $ 960 | $ 960 |
| Conversion to common shares (note 15(a)(i)), net of costs | — | (960) | (960) |
| Amortization and accretion | — | — | — |
| Carrying and fair value amount at December 31, 2013 | $ — | $ — | $ — |

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 11. Pension and other post-employment benefits

In conjunction with recent utilities acquisitions, the Company assumed defined benefit pension and OPEB plans for qualifying employees in the related acquired businesses. The legacy plans of the electricity and gas utilities are non-contributory defined pension plans covering substantially all employees. Benefits are based on each employee's years of service and compensation. Liberty Utilities initiated a defined benefit cash balance pension plan covering substantially all its new employees and current employees at its water utilities, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. The Company's policy is to make pension contributions within the range determined by generally accepted actuarial principles. The OPEB plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must cover a portion of the cost of their coverage.

The Company acquired the Pine Bluff Water System, the Peach State Gas System and New England Gas System in 2013; therefore, the pension and OPEB implications for those current acquisitions are not included in the December 31, 2012 comparative information.

(a) Net pension and OPEB obligation

The following table sets forth the projected benefit obligations, fair value of plan assets, and funded status of the Company's plans as at December 31:

| | Pension benefits 2013 | Pension benefits 2012 | OPEB 2013 | OPEB 2012 |
|---|---|---|---|---|
| **Change in projected benefit obligation** | | | | |
| Projected benefit obligation, at beginning of year | $ 104,291 | $ 239 | $ 31,674 | $ — |
| Projected benefit obligation assumed from business combination | 73,601 | 101,840 | 17,943 | 30,637 |
| Modifications to pension plan | 81 | | | — |
| Service cost | 3,273 | 1,288 | 1,602 | 803 |
| Interest cost | 4,350 | 1,906 | 1,508 | 606 |
| Actuarial (gain)/loss | (11,395) | 2,736 | (8,499) | 857 |
| Benefits paid | (3,597) | (1,507) | (1,158) | (601) |
| Loss/(gain) on foreign exchange | 7,509 | (2,211) | 2,329 | (628) |
| Projected benefit obligation at end of year | $ 178,113 | $ 104,291 | $ 45,399 | $ 31,674 |
| **Change in plan asset** | | | | |
| Fair value of plan assets at beginning of year | 66,524 | 203 | 10,195 | — |
| Plan assets acquired in business combination | 57,285 | 68,045 | 658 | 10,786 |
| Actual return on plan assets | 10,733 | 1,223 | 1,730 | — |
| Employer contributions | 3,013 | — | 1,208 | 231 |
| Benefits paid | (3,597) | (1,507) | (1,158) | (601) |
| Loss/(gain) on foreign exchange | 5,322 | (1,440) | 762 | (221) |
| Fair value of plan assets at end of year | $ 139,280 | $ 66,524 | $ 13,395 | $ 10,195 |
| Unfunded status | $ (38,833) | $ (37,767) | $ (32,004) | $ (21,479) |
| Amounts recognized in the consolidated balance sheets consists of: | | | | |
| Current liabilities | (305) | — | — | — |
| Non-current liabilities | (38,528) | (37,767) | (32,004) | (21,479) |
| Net amount recognized | $ (38,833) | $ (37,767) | $ (32,004) | $ (21,479) |

*(in thousands of Canadian dollars except as noted and amounts per share)*

**11. Pension and other post-employment benefits (continued)**

(b) Net pension and OPEB obligation

The accumulated benefit obligation for the pension plans was $162,179 and $97,687 at December 31, 2013 and 2012, respectively.

The amounts recognized in accumulated other comprehensive loss before tax were as follows:

| | Accumulated other comprehensive income | |
|---|---|---|
| | **Pension** | **OPEB** |
| Balance, January 1, 2012 | $ 53 | $ — |
| Current year net actuarial gain | 3,298 | 857 |
| Amortization of net actuarial loss | (2) | (32) |
| Foreign exchange | (16) | (4) |
| Balance at December 31, 2012 | $ 3,333 | $ 821 |
| Current year net actuarial loss | (18,011) | (9,644) |
| Current year prior service loss | 82 | — |
| Amortization of net actuarial loss | (23) | (26) |
| Foreign exchange | 234 | (234) |
| Balance at December 31, 2013 | $ (14,385) | $ (9,083) |

(c) Assumptions

Weighted average assumptions used to determine net benefit cost for 2013 and 2012 were as follows:

| | Pension benefits | | OPEB | |
|---|---|---|---|---|
| | **2013** | **2012** | **2013** | **2012** |
| Discount rate | 3.68% | 3.89% | 3.69% | 3.97% |
| Expected return on assets | 5.51% | 5.50% | 5.18% | 4.66% |
| Rate of compensation increase | 3.13% | 3.31% | 2.97% | N/A |
| Healthcare cost trend rate | | | | |
| Before Age 65 | | | 7.68% | 8.48% |
| Age 65 and after | | | 7.68% | 7.50% |
| Assumed Ultimate Medical Inflation Rate | | | 4.80% | 5.00% |
| Year in which Ultimate Rate is reached | | | 2019 | 2017 |

Weighted average assumptions used to determine net benefit obligation for 2013 and 2012 were as follows:

| | Pension benefits | | OPEB | |
|---|---|---|---|---|
| | **2013** | **2012** | **2013** | **2012** |
| Discount rate | 4.55% | 3.62% | 4.60% | 3.75% |
| Expected return on assets | 7.00% | 5.50% | 5.53% | 4.66% |
| Rate of compensation increase | 2.97% | 3.09% | 2.97% | N/A |

In selecting an assumed discount rate, the Company uses a modeling process that involves selecting a portfolio of high-quality corporate debt issuances (AA- or better) whose cash flows (via coupons or maturities) match the timing and amount of the Company's expected future benefit payments. The Company considers the results of this modeling process, as well as overall rates of return on high-quality corporate bonds and changes

*(in thousands of Canadian dollars except as noted and amounts per share)*

**11. Pension and other post-employment benefits (continued)**

(c) Assumptions (continued)

in such rates over time, to determine its assumed discount rate. The rate of return assumptions are based on projected long-term market returns for the various asset classes in which the plans are invested, weighted by the target asset allocations

The effect of a one percent change in the assumed health care cost trend rate (HCCTR) for 2013 is as follows:

| | 2013 |
|---|---|
| Effect of a 1 percentage point increase in the HCCTR on: | |
| Year-end benefit obligation | $ 5,829 |
| Total service and interest cost | 580 |
| Effect of a 1 percentage point decrease in the HCCTR on: | |
| Year-end benefit obligation | $ (4,427) |
| Total service and interest cost | (456) |

(d) Benefit costs

The following table lists the components of net benefit costs for the pension plans and OPEB recorded as part of administrative expenses in the consolidated statements of operations. The employee benefit costs related to business acquired are recorded in the consolidated statements of operations from the date of acquisition.

| | Pension benefits | | OPEB | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Service cost | $ 3,273 | $ 1,288 | $ 1,602 | $ 803 |
| Interest cost | 4,350 | 1,906 | 1,508 | 606 |
| Expected return on plan assets | (4,160) | (1,785) | (602) | — |
| Amortization of net actuarial loss | 23 | 2 | 26 | 32 |
| Net benefit cost | $ 3,486 | $ 1,411 | $ 2,534 | $ 1,441 |

The net actuarial gain for the defined benefit pension plans and OPEB that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $283 and $608, respectively.

(e) Plan assets

The Company’s investment strategy for its pension and post-retirement plan assets is to maintain a diversified portfolio of assets with the primary goal of meeting long-term cash requirements as they become due.

The Company's target asset allocation is as follows:

| Asset Class | Target (%) | Range (%) |
|---|---|---|
| Equity Securities | 79% | 48.9%-88.5% |
| Debt Securities | 17% | 21.1%-51.1% |
| Other | 4% | 0%-11.5% |

The fair values of investments as at December 31, 2013, by asset category, are as follows:

| Asset Class | Level 1 | Percentage |
|---|---|---|
| Equity Securities | 110,073 | 79% |
| Debt Securities | 23,173 | 17% |
| Other | 6,035 | 4% |

As at December 31, 2013, the funds do not hold any material investments in APUC.

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 11. Pension and other post-employment benefits (continued)

(f) Cash flows

The Company expects to contribute $7,539 to its pension plans and $1,339 to its post retirement benefit plans in 2014.

The expected benefit payments over the next ten years are as follows:

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019-2023 |
|---|---|---|---|---|---|---|
| Pension plan | $ 8,320 | $ 8,238 | $ 8,812 | $ 9,374 | $ 9,839 | $ 55,838 |
| OPEB | 1,339 | 1,247 | 1,400 | 1,547 | 1,727 | 11,176 |

(g) Defined contribution pension plans

The Company also provides defined contribution pension plans to its employees. The Company's contributions for 2013 were $2,437 (2012 - $1,108).

## 12. Mandatorily redeemable Series C preferred shares

Effective January 1, 2013, the Company issued 100 redeemable Series C preferred shares in exchange for Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of APCo and the legal owner of the St. Leon Wind Facility (note 21). Thirty-six of the Series C preferred shares are owned by related parties controlled by executives of the Company. The preferred shares are mandatorily redeemable in 2031 for $53,400 per share (fifty-three thousand and four hundred dollars per share) and have a contractual cumulative cash dividend paid quarterly until the date of redemption based on a prescribed payment schedule detailed below. As these shares are mandatorily redeemable for cash they are accounted for as liabilities in the financial statements. The cumulative dividends are indexed in proportion to the increase in CPI over the term of the shares. The dividend is intended to approximate the distributions that otherwise would have accrued to holders of Class B limited partnership units. The Series C Shares are convertible into common shares at the option of the holder and the Company, at any time after May 20, 2031 and before June 19, 2031, at a conversion price of $53,400 per share.

The Series C preferred shares were initially measured at their estimated fair value of $18,497 based on the present value of the expected contractual cash flows including dividends and redemption amount, discounted at a rate of 5.0%. The recognition of the initial fair value of $18,497 resulted in an adjustment to equity of the shareholders of the Company as the Class B shares had a nominal carrying amount prior to the exchange. The preferred shares are accounted for under the effective interest method, resulting in accretion of interest expense over the term of the shares. Dividend payments are recorded as a reduction of the Series C Preferred Share carrying value.

| Estimated dividend payments due in the next five years and dividend and redemption payments thereafter are: | |
|---|---|
| 2014 | $ 1,109 |
| 2015 | 1,077 |
| 2016 | 946 |
| 2017 | 895 |
| 2018 | 1,125 |
| Thereafter to 2031 | 20,859 |
| Redemption amount | 5,340 |
| | 31,351 |
| Less amounts representing interest | (12,546) |
| | 18,805 |
| Less current portion | (1,038) |
| | $ 17,767 |

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 13. Other assets

Other assets consist of the following:

| | 2013 | 2012 |
|---|---|---|
| Restricted cash | $ 6,021 | $ 7,063 |
| Deferred financing costs | 9,011 | 8,706 |
| Other | 3,752 | 4,251 |
| | $ 18,784 | $ 20,020 |

## 14. Other long-term liabilities

Other long-term liabilities consist of the following:

| | 2013 | 2012 |
|---|---|---|
| Asset retirement obligations | $ 9,508 | $ 7,088 |
| Customer deposits | 8,774 | 5,620 |
| Provision for injury and damages | 1,215 | 3,480 |
| Deferred water rights inducement | 2,764 | 2,845 |
| Contingent consideration | 1,102 | 1,031 |
| Other | 4,580 | 5,177 |
| | 27,943 | 25,241 |
| Less: current portion | (7,451) | (4,352) |
| | $ 20,492 | $ 20,889 |

The asset retirement obligations mainly relate to legal requirements to: (i) remove wind farm facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (clean of natural gas and PCB contaminants) and cap gas mains within the gas distribution and transmission system when mains are retired in place, or dispose of sections of gas main when removed from the pipeline system, (iii) clean and remove storage tanks containing waste oil and other waste contaminants, and (iv) remove asbestos upon major renovation or demolition of structures and facilities.

## 15. Shareholders' capital

(a) Common shares

Number of common shares:

| | 2013 | 2012 |
|---|---|---|
| Common shares, beginning of period | 188,763,486 | 136,122,780 |
| Conversion and redemption of convertible debentures (i) | 150,816 | 24,991,784 |
| Conversion of subscription receipts (ii) | 15,223,016 | 26,380,750 |
| Issuance of shares under the dividend reinvestment (iii) and employee share purchase plans (c(ii)) | 2,211,667 | 1,268,172 |
| Common shares, end of period | 206,348,985 | 188,763,486 |

**Authorized**

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the Board); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC; subject to the rights of any shares having priority over the common shares, of which none are authorized or outstanding.

**15. Shareholders' capital (continued)**

(a) Common shares (continued)

**Authorized (continued)**

On April 23, 2013, the Company's shareholders renewed its shareholders' rights plan (the "Rights Plan"). The Rights Plan has a term of three years. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board of Directors of APUC.

(i) Conversion and redemption of convertible debentures

In 2013, $960 (2012 - $61,611) of Series 3 Debentures were redeemed for 150,816 (2012 - 14,669,266) shares of APUC.

In 2012, the remaining principal amount of $59,957 of Series 2A Debentures were redeemed for 10,322,518 common shares of APUC.

(ii) Subscription receipts

On March 26, 2013, in connection with the acquisition of the Peach State Gas system the Company issued 3,960,000 common shares at a price of $7.40 per share for total proceeds of $29,304 pursuant to a subscription receipt agreement with Emera.

On May 14, 2012, in connection with the acquisition of Granite State Electric System and EnergyNorth Gas System, the Company issued 12,000,000 common shares at a price of $5.00 per share to Emera pursuant to a subscription receipt agreement. The $60,000 cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisitions.

On June 29, 2012, in connection with the acquisition of Sandy Ridge Wind Facility the Company received $15,000 from Emera relating to 2,614,006 subscription receipts representing a price of $5.74 per share and issued common shares relating to these subscription receipts in July 2012.

On July 31, 2012, in connection with the acquisition of the Midwest Gas System the Company issued 6,976,744 common shares at a price of $6.45 per share to Emera pursuant to a subscription receipt agreement. The $45,000 cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisition.

On December 10, 2012, in connection with the acquisition of Senate and Minonk Wind Facilities, the Company received $45,000 from Emera relating to the exercise of 7,842,016 subscription receipts at a price of $5.74 per subscription receipt pursuant to a subscription receipt agreement. The subscription receipts were converted to 7,842,016 common shares on February 14, 2013.

On December 21, 2012, in connection with the acquisition of Emera's noncontrolling interest in Calpeco Electric System, the Company received $38,756 from Emera related to the exercise of 8,211,000 subscription receipts at a price of $4.72 per subscription receipt pursuant to a subscription receipt agreement. On December 27, 2012, Emera exercised 4,790,000 of these subscription receipts and the Company issued 4,790,000 common shares in exchange. On February 14, 2013, the balance of 3,421,000 subscription receipts were exercised by Emera and the Company issued 3,421,000 common shares in exchange.

Following the above noted subscription receipts transactions, as of December 31, 2013 all subscriptions receipts had been exercised for cash and converted to common shares.

**15. Shareholders' capital (continued)**

(a) Common shares (continued)

(iii) Dividend reinvestment plan

The Company has a Common Shareholder Dividend Reinvestment Plan, which provides an opportunity for shareholders to reinvest dividends for the purpose of purchasing common shares. Additional Common Shares acquired through the reinvestment of cash dividends will be purchased in the open market or will be issued by APUC at a discount of up to 5% from the average market price, all as determined by the Company from time to time. Subsequent to year-end, APUC issued an additional 501,818 shares under the dividend reinvestment plan.

(b) Preferred shares

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board of Directors of APUC. On November 9, 2012, APUC issued 4,800,000 Series A Preferred shares, at a price of $25 per share, for aggregate proceeds of $120,000 before issuance cost of $4,700 or $3,454 net of tax.

The holders of preferred shares are entitled to receive fixed cumulative preferential dividends at an annual rate of $1.125 per share, payable quarterly, as and when declared by the Board of Directors of APUC (the "Board"). The Series A Preferred shares yield 4.5% annually for the initial six-year period up to, but excluding December 31, 2018, with the first dividend payment occurring December 31, 2012. The dividend rate will reset on December 31, 2018, and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 2.94%. The Series A preferred shares are redeemable at $25 per share at the option of the Company on December 31, 2018, and on December 31 of every fifth year thereafter. The holders of Series A Preferred shares have the right to convert their shares into Cumulative Floating Rate Preferred shares, Series B ("the Series B Preferred shares"), subject to certain conditions, on December 31, 2018, and on December 31 of every fifth year thereafter. The Series B Preferred shares carry the same features as the Series A Preferred shares, except that holders will be entitled to receive quarterly floating-rate cumulative dividends, as and when declared by the Board, at a rate equal to the then ninety-day Government of Canada treasury bill yield plus 2.94%. The holders of Series B Preferred shares will have the right to convert their Shares back into Series A Preferred shares on December 31, 2018, and on December 31 of every fifth year thereafter. The Series A Preferred shares and the Series B Preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

On January 1, 2013, the Company issued 100 redeemable Series C preferred shares in exchange for Class B limited partnership units issued by the St Leon LP. The mandatorily redeemable Series C preferred shares are recorded as a liability on the consolidated balance sheets (note 12).

Subsequent to year-end, on March 5, 2014, APUC issued 4,000,000 Series D Preferred shares, at a price of $25 per share, for aggregate proceeds of $100,000 before issuance costs of $3,900.

The holders of the Series D preferred shares are entitled to receive fixed cumulative preferential dividends at an annual rate of $1.25 per share, payable quarterly, as and when declared by the Board of Directors of APUC (the "Board"). The Series D Preferred shares yield 5.0% annually for the initial five-year period up to, but excluding March 31, 2019, with the first dividend payment occurring June 30, 2014. The dividend rate will reset on March 31, 2019, and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 3.28%. The Series D preferred shares are redeemable at $25 per share at the option of the Company on March 31, 2019, and on March 31 of every fifth year thereafter. The holders of Series D Preferred shares have the right to convert their shares into Cumulative Floating Rate Preferred shares, Series E ("the Series E Preferred shares"), subject to certain conditions, on March 31, 2019, and on March 31 of every fifth year thereafter. The Series E Preferred shares carry the same features as the Series D Preferred shares, except that holders will be entitled to receive quarterly floating-rate cumulative dividends, as and when declared by the Board, at a rate equal to the then ninety-day Government of Canada treasury bill yield plus 3.28%. The holders of Series E Preferred shares will have the right to convert their Shares back into Series D Preferred shares on March 31, 2019, and on March 31 of every fifth year thereafter. The Series D Preferred shares and the Series E Preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

*(in thousands of Canadian dollars except as noted and amounts per share)*

**15. Shareholders' capital (continued)**

(c) Share-based compensation

For the year ended December 31, 2013, APUC recorded $2,046 (2012 - $1,833) in total share-based compensation expense detailed as follows:

| | 2013 | 2012 |
|---|---|---|
| Stock options | $ 1,687 | $ 1,376 |
| Directors deferred share units | 155 | 155 |
| Employee share purchase | 75 | 42 |
| Performance share units | 129 | 260 |
| Total share-based compensation | $ 2,046 | $ 1,833 |

The compensation expense is recorded as part of administrative expenses in the consolidated statement of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2013, total unrecognized compensation costs related to non-vested options and share unit awards were $1,762 and $86 respectively, and are expected to be recognized over a period of 1.57 years and 1.0 respectively.

(i) Stock option plan

The Company's stock option plan (the "Plan") permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 10% of the number of Shares outstanding at the time the options are granted. The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Dividends on the underlying shares do not accumulate during the vesting period. Option holders may elect to surrender any portion of the vested options which is then exercisable in exchange for the In-the-Money Amount. In accordance with the Plan, the In-The-Money Amount represents the excess, if any, of the market price of a share at such time over the option price, in each case such In-the-Money amount being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historic volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

*(in thousands of Canadian dollars except as noted and amounts per share)*

**15. Shareholders' capital (continued)**

(c) Share-based compensation (continued)

(i) Stock option plan (continued)

The following assumptions were used in determining the fair value of share options granted:

| | 2013 | 2012 |
|---|---|---|
| Risk-free interest rate | 1.61% | 1.70% |
| Expected volatility | 37% | 38% |
| Expected dividend yield | 3.83% | 4.40% |
| Expected life | 8 years | 8 years |
| Weighted average grant date fair value per option | $ 2.00 | $ 1.49 |

Stock option activity during the period is as follows:

| | Number of awards | Weighted average exercise price | Weighted average remaining contractual term (years) | Aggregate intrinsic value |
|---|---|---|---|---|
| Balance at January 1, 2012 | 2,487,105 | $ 4.76 | 6.96 | $ 4,134 |
| Granted | 1,263,622 | 6.24 | 8.00 | — |
| Balance at December 31, 2012 | 3,750,727 | $ 5.25 | 6.07 | $ 5,939 |
| Granted | 816,402 | 7.72 | 8.00 | — |
| Balance at December 31, 2013 | 4,567,129 | $ 5.70 | 5.45 | $ 7,814 |
| Exercisable at December 31, 2013 | 2,466,008 | $ 4.90 | 4.96 | $ 6,018 |

ii) Employee share purchase plan

Under the Company's employee share purchase plan ("ESPP"), eligible employees may have a portion of their earnings withheld to be used to purchase the Company's common shares. The Company will match a) 20% of the employee contribution amount for the first five thousand dollars per employee contributed annually and 10% of the employee contribution amount for contributions over five thousand dollars up to ten thousand dollars annually, for Canadian employees, and b) 15% of the employee contribution amount for the first fifteen thousand dollar per employee contributed annually, for U.S. employees. Shares purchased through the Company match portion shall not be eligible for sale by the participant for a period of one year following the contribution date on which such shares were acquired. At the Company's option, the shares may be (i) issued to participants from treasury at the average share price or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares.

The Company uses the fair value based method to measure the compensation expense related to the Company's contribution. For the year ended December 31, 2013, a total of 85,410 common shares (2012 – 54,227) were issued to employees under the ESPP plan.

iii) Directors deferred share units

Under the Company's Deferred Share Unit Plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in Deferred Share Units ("DSUs") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. As at

*(in thousands of Canadian dollars except as noted and amounts per share)*

**15. Shareholders' capital (continued)**

(c) Share-based compensation (continued)

iii) Directors deferred share units (continued)

December 31, 2013, 74,786 (2012 – 50,172) DSUs were outstanding pursuant to the election of the Directors to defer a percentage of their 2013 and 2012 Director's fee in the form of DSUs.

iv) Performance share units

The Company offers a performance share unit plan to its employees as part of the Company's long-term incentive program. Performance Share Units ("PSUs") are granted annually for three-year overlapping performance cycles. PSUs vest at the end of the three-year cycle and will be calculated based on established performance criteria. At the end of the three-year performance periods, the number of shares issued can range from 0% to 184% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividends are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. The Company has a policy of repurchasing shares on the open market to satisfy PSUs exercises and expects to repurchase approximately 24,928 shares during 2014, based on estimates of PSU exercises for that period.

Compensation expense associated with PSUs is recognized rateably over the performance period and assumes that performance goals will be achieved at 100%. If goals met differ, compensation cost recognized is adjusted to reflect the performance conditions achieved.

A summary of the PSUs follows:

| | Number of awards | Weighted Average Grant-Date Fair Value | Weighted Average Remaining Contractual Term (years) | Aggregate intrinsic value |
|---|---|---|---|---|
| Balance at January 1, 2012 | 21,123 | $ 5.62 | 2.00 | $ 136 |
| Granted | 68,982 | 6.78 | 1.30 | 467 |
| Forfeited | (6,622) | 5.62 | 1.50 | (37) |
| Balance at December 31, 2012 | 83,483 | $ 6.58 | 1.80 | $ 571 |
| Granted, including dividends | 5,537 | 6.79 | 1.23 | 41 |
| Exercised | (20,640) | 6.70 | — | (151) |
| Forfeited | (2,185) | 6.70 | — | (16) |
| Balance at December 31, 2013 | 66,195 | $ 6.57 | 0.62 | $ 486 |
| Exercisable at December 31, 2013 | 24,928 | $ 6.14 | — | $ 183 |

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 16. Accumulated other comprehensive loss

Accumulated other comprehensive loss is comprised of the following balances, net of tax:

| | Foreign currency cumulative translation | Unrealized gain on cash flow hedges | Pension and post-retirement actuarial loss | Total |
|---|---|---|---|---|
| Balance, January 1, 2012 | $ (96,462) | $ — | $ (48) | $ (96,510) |
| Other comprehensive income (loss) before reclassifications | (9,495) | 3,596 | (2,459) | (8,358) |
| Amounts reclassified from accumulated other comprehensive loss | | | 1 | 1 |
| Net current period other comprehensive income | (9,495) | 3,596 | (2,458) | (8,357) |
| Balance, December 31, 2012 | $(105,957) | $ 3,596 | $ (2,506) | $(104,867) |
| Other comprehensive income (loss) before reclassifications | 39,422 | 19,421 | 16,698 | 75,541 |
| Amounts reclassified from accumulated other comprehensive loss | — | (2,113) | 29 | (2,084) |
| Net current period other comprehensive income | 39,422 | 17,308 | 16,727 | 73,457 |
| Balance, December 31, 2013 | $ (66,535) | $ 20,904 | $ 14,221 | $ (31,410) |

## 17. Noncontrolling interests

Net earnings/(loss) attributable to noncontrolling interests consists of the following:

| | 2013 | 2012 |
|---|---|---|
| Net earnings/(loss) attributable to Class B partnership units of SponsorCo | $ 9,556 | $ (4,580) |
| Net earnings/(loss) attributable to Class A partnership units | (20,408) | 10,678 |
| Other net earnings attributable to noncontrolling interests | 39 | 1,316 |
| Total net earnings/(loss) attributable to noncontrolling interests | $ (10,813) | $ 7,414 |

## 18. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board of the Company. For the year ended December 31, 2013, the Company declared dividends to shareholders on common shares totaling $68,291 (2012 - $50,196 ) or $0.3325 per common share (2012 - $0.2950 per common share). The Board declared a dividend on the Company's common shares of $0.0850 per share payable on January 15, 2014 to the shareholders of record on December 31, 2013.

For the year ended December 31, 2013, the Company declared and paid dividends to Preferred Share, Series A holders totaling $5,400 (2012 - $769 ) or $1.125 per Series A Preferred share (2012 - $0.1603 per Series A Preferred share).

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 19. Income taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 26.5% (2012 – 26.5%). The differences are as follows:

| | | 2013 | | 2012 |
|---|---|---|---|---|
| Expected income tax expense / (recovery) at Canadian statutory rate | $ | 16,072 | $ | 1,726 |
| Increase (decrease) resulting from: | | | | |
| Recognition of deferred credit | | (6,676) | | (5,092) |
| Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates | | (2,338) | | (6,282) |
| Non-taxable corporate dividend | | (2,896) | | (666) |
| Noncontrolling interests share of income | | 4,266 | | (2,835) |
| Production tax credit | | (247) | | (676) |
| Allowance for equity funds used during construction | | (694) | | (402) |
| State taxes | | 313 | | — |
| Other | | 1,355 | | (140) |
| Income tax recovery | $ | 9,155 | $ | (14,367) |

For the years ended December 31, 2013 and 2012, income/(loss) from continuing operations before taxes consists of the following:

| | | 2013 | | 2012 |
|---|---|---|---|---|
| Canadian operations | $ | 19,687 | $ | 12,251 |
| U.S. operations | | 40,962 | | (5,715) |
| | $ | 60,649 | $ | 6,536 |

As a result of the business combination transaction in 2009, APUC recorded certain additional tax attributes. These tax attributes have been recognized to the extent management believes they are more likely than not to be realized. The excess of the carrying amount of the tax attributes recorded over the consideration was recorded as a deferred credit of $55,647 on the transaction date. The deferred credit is being recognized in income as a deferred income tax recovery in relative proportion to the amount of the related tax attributes that are utilized in the period.

Income tax expense (recovery) attributable to income/(loss) consists of:

| | | Current | | Deferred | | Total |
|---|---|---|---|---|---|---|
| Year ended December 31, 2013 | | | | | | |
| Canada | $ | 1,532 | $ | 881 | $ | 2,413 |
| United States | | 994 | | 5,748 | | 6,742 |
| | $ | 2,526 | $ | 6,629 | $ | 9,155 |
| Year ended December 31, 2012 | | | | | | |
| Canada | $ | 127 | $ | (938) | $ | (811) |
| United States | | 611 | | (14,167) | | (13,556) |
| | $ | 738 | $ | (15,105) | $ | (14,367) |

*(in thousands of Canadian dollars except as noted and amounts per share)*

**19. Income taxes (continued)**

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2013 and 2012 are presented below:

| | 2013 | 2012 |
|---|---|---|
| Deferred tax assets: | | |
| Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs | $ 226,314 | $ 184,845 |
| Pension and OPEB | 31,433 | 5,011 |
| Acquisition related costs | 5,152 | 5,134 |
| Outside basis in partnership | — | 2,533 |
| Regulatory accounts | — | 4,013 |
| Financial derivatives | — | 211 |
| Environmental obligation | 23,076 | 22,414 |
| Production tax credit | 1,633 | 673 |
| Reserves not currently deductible | 2,397 | 1,276 |
| Other | 2,780 | 136 |
| Total deferred income tax assets | 292,785 | 226,246 |
| Less: Valuation allowance | (15,667) | (15,062) |
| Total deferred tax assets | 277,118 | 211,184 |
| Deferred tax liabilities: | | |
| Property, plant and equipment | (267,344) | (219,573) |
| Intangible assets | (8,321) | (5,478) |
| Outside basis in partnership | (2,210) | — |
| Regulatory accounts | (24,745) | — |
| Financial derivatives | (7,675) | — |
| Total deferred tax liabilities | (310,295) | (225,051) |
| Net deferred tax assets/(liabilities) | $ (33,177) | $ (13,867) |

The valuation allowance for deferred tax assets as of December 31, 2013 was $(15,667) (2012 $(15,062)). The valuation allowance at December 31, 2013 was primarily related to operating losses that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities (including the impact of available carry back and carry forward periods), projected future taxable income, and tax-planning strategies in making this assessment.

Deferred income taxes are classified in the financial statements as:

| | 2013 | 2012 |
|---|---|---|
| Current deferred income tax asset | $ 19,652 | $ 10,567 |
| Non-current deferred income tax asset | 86,632 | 77,497 |
| Current deferred income tax liability | (2,308) | (1,133) |
| Non-current deferred income tax liability | (137,153) | (100,798) |
| | $ (33,177) | $ (13,867) |

*(in thousands of Canadian dollars except as noted and amounts per share)*

**19. Income taxes (continued)**

As at December 31, 2013, the Company had non-capital losses carry forwards available to reduce future year's taxable income, which expire as follows:

| Year of expiry | | Non-capital loss carry forwards |
|---|---|---|
| 2015 | $ | 5,426 |
| 2016 and onwards | | 463,610 |
| | $ | 469,036 |

**20. Divestitures**

(a) EFW held for sale

During the second quarter of 2013, the Company initiated a strategic review of the Company's business plan and opportunities available for its Energy From Waste ("EFW Thermal Facility") and Brampton Cogeneration Inc. ("BCI Thermal Facility"). As a result of the review, the Company decided to sell the facilities. In the second quarter of 2013, the net assets of EFW and BCI were written down to their estimated fair value less cost of sale which resulted in a write down of the net assets of $47,651 before tax, or $35,738 net of tax of $11,913.

Subsequent to year-end, on February 7, 2014, the Company entered into an agreement to sell EFW and BCI Thermal Facilities. Accordingly, the determination of the fair value of the net assets of EFW and BCI Thermal Facilites was revised to reflect the estimated selling price, which resulted in a further write down of the net assets of $9,200 before tax, or $6,800 net of tax of $2,400 as at December 31, 2013. The transaction is subject to regulatory approvals, and is expected to close in the first half of 2014. The final selling price is also subject to customary closing adjustments.

(b) Restatement of 2012 comparatives

As a result of the designation of EFW and BCI Thermal Facilities as discontinued operations in 2013, the Company is required to reclassify these assets as discontinued operations in the comparative 2012 financial statements. As a result, the assets, PPE and liabilities have been reclassified to assets held for sale and liabilities held for sale in the 2012 comparative figures. Similarly, the 2012 comparative statement of operations and statement of cash flows have been reclassified to reflect the earnings and cash flow from these assets as discontinued operations. In addition, the 2012 comparative amounts in notes 5, 8, 9, and 19, have also been reclassed from the amounts previously reported in the prior year to reflect this change.

(c) Sale of U.S. Hydro facilities

On June 29, 2013, APCo sold 9 small U.S. hydroelectric generating facilities that were no longer considered strategic to the ongoing operations of the Company, for gross proceeds of U.S. $23,400 for a gain on sale of U.S. $960, net of tax recovery of U.S. $1,605. The sale of the last small U.S. hydroelectric generating facilities is expected to close in 2014 for U.S. $3,600.

In August 2012, APCo sold a small U.S. Hydro facility for gross proceeds of $350 for a loss on sale, net of tax of $253.

*(in thousands of Canadian dollars except as noted and amounts per share)*

**20. Divestitures (continued)**

(d) Results from discontinued operations

The assets of EFW and BCI Thermal Facilities and the small U.S. hydroelectric facilities are presented as assets held for sale on the consolidated balance sheets and the operating results from these facilities are disclosed as discontinued operations on the consolidated financial statements.

The summary of operating results and cash flows from discontinued operations for the years ended December 31 is as follows:

| | 2013 | 2012 as reported | 2012 EFW/ BCI adjustments | 2012 as reclassed |
|---|---|---|---|---|
| Non-regulated energy sales | 9,327 | 2,870 | 6,800 | 9,670 |
| Waste disposal fees | 8,160 | — | 14,288 | 14,288 |
| Other and interest income | 336 | — | (6) | (6) |
| Operating and administrative expenses | (19,720) | (3,241) | (12,544) | (15,785) |
| Foreign exchange | 80 | — | — | — |
| Depreciation of property, plant and equipment | (2,483) | (1,279) | (5,194) | (6,473) |
| Interest expense | (58) | (4) | (317) | (321) |
| Gain on sale of assets | 1,016 | — | — | — |
| Write-off of accounts receivable | (262) | — | — | — |
| Write-down of long-lived assets | (56,898) | (253) | (23) | (276) |
| Gain/(loss) from discontinued operations, before income taxes | (60,502) | (1,907) | 3,004 | 1,097 |
| Income tax recovery/(expense) | 18,491 | 750 | (804) | (54) |
| Gain/(loss) from discontinued operations, net of income taxes | (42,011) | (1,157) | 2,200 | 1,043 |
| Add: | | | | |
| Depreciation of property, plant and equipment | 2,483 | 1,279 | 5,194 | 6,473 |
| Write-off of accounts receivable | 262 | — | — | — |
| Write-down of long-lived assets | 56,898 | 253 | 23 | 276 |
| Net proceeds of disposition | 22,052 | — | — | — |
| Contingent liability | (613) | — | — | — |
| Income tax expense/(recovery) | (18,491) | (750) | 804 | 54 |
| Increase/(decrease) in cash and cash equivalents from discontinued operations | 20,580 | (375) | 8,221 | 7,846 |

*(in thousands of Canadian dollars except as noted and amounts per share)*

**20. Divestitures (continued)**

(d) Results from discontinued operations (continued)

Assets held-for-sale as at December 31, were as follows:

| | 2013 | 2012 as reported | 2012 EFW/ BCI Adjustments | 2012 Reclassed |
|---|---|---|---|---|
| Property, plant and equipment | $ 21,193 | $ 24,390 | $ 76,437 | $ 100,827 |
| Accounts receivable and prepaid expenses | 2,734 | — | 2,510 | 2,510 |
| Total assets held for sale | $ 23,927 | $ 24,390 | $ 78,947 | $ 103,337 |
| Less current assets held for sale | (23,927) | (24,390) | (2,510) | (26,900) |
| Non-current assets held for sale | $ — | $ — | $ 76,437 | $ 76,437 |

Liabilities held-for-sale as at December 31, were as follows:

| | 2013 | 2012 as reported | 2012 EFW/ BCI Adjustments | 2012 Reclassed |
|---|---|---|---|---|
| Accounts payable and accrued liabilities | $ 1,471 | $ — | $ 1,211 | $ 1,211 |

**21. Related party transactions**

Ian Robertson and Chris Jarratt ("Senior Executives"), respectively Chief Executive Officer and Vice-Chair of APUC are indirect shareholders of Algonquin Power Management Inc. ("APMI"), the former manager of the Company and several related affiliates (collectively the "Parties"). Prior to 2010, there were several related party transactions and co-owned assets which existed pursuant to the external management structure before the internalization of management which occurred on December 21, 2009.

In 2011, the Board formed an independent committee ("Independent Board Committee") and initiated a process to review all of the remaining business associations with the Parties in order to reduce and/or eliminate these relationships. The Independent Board Committee engaged independent consultants and advisors to assist with this process and to provide advice in respect thereof. Specifically, the independent advisors provided advice to the Independent Board Committee in relation to the valuations of the generating assets, tax and legal matters.

The process initiated in 2011 was completed in November 2013 and all related party transactions between APUC and the Parties have been addressed to the satisfaction of the Independent Board Committee and the Board as discussed below.

The following describes the business associations and resolution with APMI and Senior Executives:

*Due to and from related parties*

As at December 31, 2013, due from related parties include $nil (December 31, 2012 - $816) owed to APUC from the Parties and due to related parties include $nil (December 31, 2012 - $1,811) owed to the Parties.

Prior to 2010, APMI was the manager of Algonquin Power Income Fund ("APIF"); the predecessor organization to APUC; and at the time of the internalization of management, had a number of fees under negotiation as described below:

- APMI was a one of the original developers of the Red Lily I wind project and was entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. In 2011, APUC acquired APMI's interest in this royalty.
- As part of the project to re-power the Sanger Thermal Facility in 2008, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee.

**21. Related party transactions (continued)**

*Due to and from related parties (continued)*

- During 2007, APUC allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee for which APMI was entitled to a portion thereof.
- During 2008, APMI provided construction supervision services for the construction of the BCI and was entitled to a construction supervision fee on the BCI project.
- As manager of APIF, APMI was entitled to management fees pursuant to a management agreement and the 2009 Q4 management fee was not made to APMI. In addition, pursuant to the management agreement, APMI incurred and was entitled to reimbursement of reasonable expenses in 2009 which was also not reimbursed by APUC.

Effective December 31, 2013, APUC paid the Parties $1,829 in connection with outstanding fees and the Parties paid APUC $812 in connection with reimbursement of expenses both in full satisfaction of the related party balances.

*Equity interests in Rattle Brook, Long Sault, BCI*

The Parties own interests in three power generation facilities in which APUC also has an interest in. A brief description of the facilities is provided as follows:

- Rattle Brook is a 4 MW hydroelectric generating facility ("Rattle Brook") constructed in 1998 in which APUC owns a 45% interest and Senior Executives hold an equity interest in the remaining 55%.
- Long Sault Hydro Facility is an 18MW hydroelectric generating facility constructed in 1997. APUC acquired its interest in Long Sault by way of subscribing to two notes from the original partners. One of the original partners; an affiliate of APMI; is entitled to receive 5% of the equity cash flows commencing in 2014.
- Brampton Cogeneration is an energy supply facility which sells steam produced by EFW. In 2004, APMI acquired 50 Class B partnership units in BCI entitling them to 50% of the cash flow above 15% return on the investment.

Effective December 31, 2013, APUC acquired the Parties' shares of Algonquin Power Corporation Inc. ("APC") which owns the partnership interest in the 18MW Long Sault Rapids hydroelectric facility and the partnership interest in the Brampton cogeneration plant for an amount equal to $3,780. As APUC already consolidates Long Sault as a VIE, the acquisition of this partnership interest was treated as an equity transaction. The payment resulted in an adjustment to deferred tax liability of $10,692 in regards to tax attributes acquired with the partnership interests and an adjustment of $14,601 to equity of the shareholders of the Company as the partnership interests had a nominal carrying amount prior to the exchange.

In addition, APUC sold its 45% interest in the 4MW Rattle Brook hydroelectric facility to the Parties for gross proceeds $3,408 for a loss on sale, net of tax of $422.

APUC earned a fee of $400 from APC during the year ended December 31, 2013 (2012 -$nil) related to settlement of the related party transactions.

*St Leon LP Units*

Third party investors, including Senior Executives previously held 100 Class B limited partnership units issued by the St. Leon Limited Partnership which is the legal owner of the St. Leon Wind Facility. The Class B units held by Senior Executives received cash distributions of $nil for the year ended December 31, 2013 (2012 - $175).

On January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the 100 Class B units (note 10) including 36 units held indirectly by Senior Management. The Series C preferred shares provide dividends identical to what is expected from the Class B units, as determined by independent consultants retained by the Independent Board Committee. As of January 1, 2013, no Senior Executives have any further direct or indirect ownership of the St. Leon Wind Facility.

*Office Facilities*

APUC has leased its head office facilities since 2001 on a triple net basis from an entity partially owned by the Senior Executives. Base lease costs for the year ended December 31, 2013 were $310 (2012 - $333). The current office lease for a portion of its head office facilities expires on December 31, 2015. Subsequent to year-end, on January 31, 2014, APUC, through a wholly owned subsidiary, acquired from a third party a new office facility (note 5) which is suitable for meeting the future head office needs of APUC. Upon occupancy of the new head office facilities which is anticipated to occur in 2014, it is expected that the currently occupied premises will be subleased to third parties.

**21. Related party transactions (continued)**

*Chartered Aircraft*

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into an agreement to charter aircraft in which the Senior Executives have a partial ownership. In 2004 APUC remitted $1,300 to an affiliate of APMI as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. By the end of 2012 the entire advance had been amortized against expense reimbursements and therefore no amortization expense for the year ended December 31, 2013 related to the advance was incurred (2012 - $279). During the year ended December 31, 2013, APUC reimbursed direct costs in connection with the use of the aircraft of $472 (2012 - $598). As of December 31, 2013, the remaining amount of the advance was $nil (December 31, 2012 - $nil) and as a result the Independent Board Committee is satisfied that the advance arrangement has concluded. The Independent Board Committee and the Parties have agreed that all future utilization of chartered aircraft will be undertaken through third party charter operators at fair market value and under arrangements in which the Senior Executives have no interest.

*Operations Services*

APUC provided supervisory services on a cost recovery basis for one small hydroelectric generating facility where Senior Executives hold an equity interest. The fees paid in relation to the supervisory management services were nominal for the years ended December 31, 2013 and 2012. This agreement terminated on December 31, 2013.

*Trafalgar*

APCo owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, Trafalgar went into default under its debt obligations and an affiliate of APMI moved to foreclose on the assets. Subsequently Trafalgar went into bankruptcy. APUC and the affiliate of APMI have been jointly involved in litigation and in bankruptcy proceedings with Trafalgar since 2004. APMI initially funded $2 million in legal fees prior to 2004.

In 2004, the Board reimbursed APMI $1 million of the total third party legal fees (which to that point totalled $2 million), and APUC agreed to fund future legal fees, third party costs and other liabilities. It was agreed that any net proceeds from the lawsuits would be shared proportionally to the quantum of net costs funded by each party.

**Other Related Party Transactions**

A member of the Board of Directors of APUC is an executive at Emera. Related Party Transactions between APUC and Emera are discussed in the section below titled "Transactions with Emera".

An individual related to an executive of APUC provided market research consulting services to certain subsidiaries of Liberty Utilities. Related Party Transactions between Liberty Utilities and the consultant are discussed in the section below titled "Other".

*Transactions with Emera*

- For the year ended December 31, 2013, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $6,042 (2012 - U.S. $6,096 ). In 2011, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S. $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.
- In 2011, APUC provided a corporate guarantee in an amount of U.S. $1,000 to a subsidiary of Emera providing lead market participant services for fuel capacity and forward reserve markets to ISO NE for the Windsor Locks facility. There has not been any transaction under this contract in the last two years.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

*Other*

An individual related to an executive of APUC provided market research consulting services to certain subsidiaries of Liberty Utilities. During the year ended December 31, 2013 APUC paid $29 (2012 -$nil) in relation to these services.

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 22. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the common shareholders of the Company and the weighted average number of common shares outstanding during the year. Diluted net income per share is computed using the weighted-average number of common shares and, if dilutive, potential common shares outstanding during the period. Potential common shares consist of the incremental common shares issuable upon the exercise of stock options, PSUs, DSUs, shareholders' rights and convertible debentures. The dilutive effect of outstanding stock options, PSUs, DSUs and shareholders' rights is reflected in diluted earnings per share by application of the treasury stock method while the dilutive effect of convertible debentures is reflected in diluted earnings per share by application of the as if converted method.

The reconciliation of the net income and the weighted average shares used in the computation of basic and diluted earnings per share are as follows:

| | 2013 | 2012 |
|---|---|---|
| Net earnings attributable to shareholders of APUC | $ 20,296 | $ 14,532 |
| Series A preferred shares dividend | 5,400 | 769 |
| Net earnings attributable to common shareholders of APUC | $ 14,896 | $ 13,763 |
| Discontinued operations | $ (42,011) | $ 1,043 |
| Net earnings attributable to common shareholders of APUC from continuing operations - Basic and Diluted | $ 56,907 | $ 12,720 |
| Weighted average number of shares | | |
| Basic | 204,350,689 | 158,304,340 |
| Dilutive effect of share-based awards | 980,697 | 605,281 |
| Diluted | 205,331,386 | 158,909,621 |

The shares potentially issuable as a result of the convertible debentures as well as stock options of 885,418 respectively (2012 – 1,354,531) are excluded from this calculation as they are anti-dilutive.

## 23. Commitments and contingencies

(a) Contingencies

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these financial statements, with the exception of those matters described below. Accruals for any contingencies related to these items are recorded in the financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

i) On October 21, 2011 the Québec Court of Appeal ordered a subsidiary of APUC to pay approximately $5,400 (including interest) to the government of Québec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years.

The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $6,000. In 2012, the Company paid an amount of $1,884 to the government of Québec in relation to the early years covered by the claim in order to mitigate the impact of accruing interests on any amount ultimately determined to be payable or recoverable.

ii) The normal ongoing operations and historic activities of the Company are subject to various federal, state and local environmental laws and regulations and are regulated by agencies such as the United States Environmental Protection Agency, the New Hampshire Department of Environmental Services and the Massachusetts Department of Environmental Protection.

*(in thousands of Canadian dollars except as noted and amounts per share)*

**23. Commitments and contingencies (continued)**

(a) Contingencies (continued)

ii) Like most other industrial companies, the gas and electric distribution utilities generate some hazardous wastes. Under federal and state laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred. In the case of regulated utilities these costs are often allowed in rate case proceedings to be recovered from rate payers over a specified period.

Prior to their acquisition by Liberty Utilities, EnergyNorth Gas, Granite State Electric and New England Gas Systems were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("MGP") and related facilities. The Company is currently investigating and remediating, as necessary, those MGP and related sites in accordance with plans submitted to the agency with authority for each of the respective sites.. The Company believes that obligations imposed on it because of those sites will not have a material impact on its results of operations or financial position.

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $77,729 which at discount rates ranging from 3.8% to 4.5% represents the recorded accrual of $69,555 at December 31, 2013 (December 31, 2012 - $57,340). Following resolution of certain environmental liabilities subsequent to year-end, the remaining undiscounted, unescalated costs of these MGP-related environmental cleanup activities should be reduced by $4,200 with a corresponding reduction to the related regulatory asset.

By rate orders, the Regulator provided for the recovery of actual expenditures for site investigation and remediation over a period of 7 years and accordingly, at December 31, 2013 the Company has reflected a regulatory asset of $80,438 (December 31, 2012 - $59,789) for the MGP and related sites (note 7(a)).

Estimated cash flows for site investigation and remediation costs in the next five years and thereafter are as follows:

| | |
|---|---|
| 2014 | $ 10,111 |
| 2015 | 27,285 |
| 2016 | 17,873 |
| 2017 | 2,128 |
| 2018 | 1,784 |
| Thereafter to 2046 | 18,548 |
| | $ 77,729 |

(b) Commitments

In addition to the commitments related to the proposed acquisitions disclosed in note 3 the following significant commitments exist at December 31, 2013.

As a result of the dam safety legislation passed in Quebec (Bill C93), APUC has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. The assessments have identified a number of remedial measures required to meet the new safety standards. APUC currently estimates further capital expenditures of approximately 15,400 over a period of five years related to compliance with the legislation.

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 23. Commitments and contingencies (continued)

(b) Commitments (continued)

APUC has outstanding purchase commitments for power purchases, gas delivery, service and supply, service agreements, capital project commitments and operating leases. Detailed below are estimates of future commitments under these arrangements:

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Purchased power | $ 64,626 | $ 46,865 | $ — | $ — | $ — | $ — | $ 111,491 |
| Gas delivery, service and supply agreements | 42,125 | 26,364 | 13,812 | 9,869 | 9,476 | 54,495 | 156,141 |
| Service agreements | 24,130 | 24,371 | 28,922 | 29,639 | 27,897 | 498,342 | 633,301 |
| Capital projects | 49,337 | 2,260 | — | — | — | — | 51,597 |
| Operating leases | 5,125 | 4,551 | 3,944 | 3,733 | 3,551 | 85,213 | 106,117 |
| Total | $185,343 | $104,411 | $46,678 | $43,241 | $ 40,924 | $638,050 | $1,058,647 |

Calpeco Electric System has entered into a five year all-purpose power purchase agreement with NV Energy to provide its full electric requirements at NV Energy's "system average cost" rates. The PPA has an effective starting date of January 1, 2011 with a five year renewal option. The commitment amounts included in the table above are based on market prices as of December 31, 2013. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism. Granite State Electric System has several types of contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment.

Subsequent to year-end on March 11, 2014, APCo entered into a Turbine Supply Agreement with a counterparty with respect to the Morse Wind Project. Amounts related to this contract are included in the above table.

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 24. Non-cash operating items

The changes in non-cash operating items from discontinued operations is comprised of the following:

| | 2013 | 2012 |
|---|---|---|
| Accounts receivable | $ (213) | $ (313) |
| Prepaid expenses | (11) | 135 |
| Accrued liabilities | 260 | (230) |
| | $ 36 | $ (408) |

The changes in non-cash operating items is comprised of the following:

| | 2013 | 2012 |
|---|---|---|
| Accounts receivable | $ (49,888) | $ (14,582) |
| Related party balances | (996) | 1,476 |
| Natural gas inventory | (6,330) | — |
| Supplies and consumable inventory | (525) | (3,621) |
| Income tax receivable | 177 | (423) |
| Prepaid expenses | (485) | (4,764) |
| Accounts payable | (29,292) | (7,553) |
| Accrued liabilities | 37,023 | 31,335 |
| Current income tax liability | 1,399 | 131 |
| Net regulatory assets and liabilities | 1,098 | (5,475) |
| | $ (47,819) | $ (3,476) |

## 25. Segmented information

APUC has two business units: APCo which owns or has interests in renewable energy facilities and thermal energy facilities and Liberty Utilities which owns and operates utilities in the United States of America providing water, wastewater and local electric and natural gas distribution services.

Within APCo there are two operating segments: Renewable Energy and Thermal Energy. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. The Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities.

Within Liberty Utilities there are the following operating segments: Liberty Utilities (West), Liberty Utilities (Central) and Liberty Utilities (East). Liberty Utilities (West) is comprised of Calpeco Electric System and the water distribution and wastewater utilities located in Arizona. Liberty Utilities (Central) is comprised of the Midwest Gas System and the water distribution and wastewater utilities located in Texas, Missouri and Illinois. Liberty Utilities (East) is comprised of the New Hampshire Electric and Gas Systems, Peach State Gas Gystem and New England Gas System.

The development activities of APCo are reported under Renewable Energy or Thermal Energy as appropriate. For purposes of evaluating divisional performance, the Company allocates the realized portion of any gains or losses on financial instruments to specific divisions. The unrealized portion of any gains or losses on derivatives instruments not designated in a hedging relationship is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment.

The results of operations and assets for these segments are as follows:

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 25. Segmented information (continued)

### Operational segments (continued)

| | Year ended December 31, 2013 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Algonquin Power | | | Liberty Utilities | | | | Corporate | Total |
| | Renewable Energy | Thermal Energy | Total | Central | West | East | Total | | |
| **Revenue** | | | | | | | | | |
| Regulated electricity sales and distribution | $ — | $ — | $ — | $ — | $ 77,814 | $ 88,342 | $ 166,156 | $ — | $ 166,156 |
| Regulated gas sales and distribution | — | — | — | 78,857 | — | 182,815 | 261,672 | — | 261,672 |
| Regulated water reclamation and distribution | — | — | — | 18,242 | 39,108 | — | 57,350 | — | 57,350 |
| Non-regulated energy sales | 145,661 | 34,530 | 180,191 | — | — | — | — | — | 180,191 |
| Other revenue | 7,058 | 2,442 | 9,500 | — | 22 | — | 22 | 400 | 9,922 |
| Total revenue | 152,719 | 36,972 | 189,691 | 97,099 | 116,944 | 271,157 | 485,200 | 400 | 675,291 |
| **Operating expenses** | 48,966 | 8,514 | 57,480 | 27,455 | 36,753 | 67,264 | 131,472 | — | 188,952 |
| **Regulated electricity purchased** | — | — | — | — | 39,750 | 57,626 | 97,376 | — | 97,376 |
| **Regulated gas purchased** | — | — | — | 46,018 | — | 102,766 | 148,784 | — | 148,784 |
| **Non-regulated fuel for generation** | — | 17,151 | 17,151 | — | — | — | — | — | 17,151 |
| | 103,753 | 11,307 | 115,060 | 23,626 | 40,441 | 43,501 | 107,568 | 400 | 223,028 |
| Depreciation of property, plant and equipment | (45,122) | (5,439) | (50,561) | (9,096) | (13,596) | (18,725) | (41,417) | — | (91,978) |
| Amortization of intangible assets | (2,652) | (856) | (3,508) | (81) | (611) | — | (692) | — | (4,200) |
| Administration expenses | (13,094) | (223) | (13,317) | (1,677) | (2,541) | (3,259) | (7,477) | (2,724) | (23,518) |
| Foreign exchange gain | — | — | — | — | — | — | — | 567 | 567 |
| Interest expense | (27,391) | (1,046) | (28,437) | (5,069) | (8,519) | (10,146) | (23,734) | (1,174) | (53,345) |
| Interest, dividend and other income | 1,867 | 193 | 2,060 | 375 | 1,395 | 1,458 | 3,228 | 2,497 | 7,785 |
| Loss on sale of asset | (750) | — | (750) | — | — | — | — | — | (750) |
| Acquisition related costs | (628) | — | (628) | (68) | — | (1,444) | (1,512) | — | (2,140) |
| Gain/(loss) on derivative financial instruments | (767) | — | (767) | — | — | — | — | 5,967 | 5,200 |
| Earnings from continuing operations before income taxes | 15,216 | 3,936 | 19,152 | 8,010 | 16,569 | 11,385 | 35,964 | 5,533 | 60,649 |
| Loss from discontinued operations before income taxes | 1,128 | (61,630) | (60,502) | — | — | — | — | — | (60,502) |
| Earnings/(loss) before income taxes | $ 16,344 | $ (57,694) | $ (41,350) | $ 8,010 | $ 16,569 | $ 11,385 | $ 35,964 | $ 5,533 | $ 147 |
| Property, plant and equipment | $1,364,843 | $ 79,828 | $1,444,671 | $ 215,090 | $ 387,715 | $ 661,228 | $ 1,264,033 | $ — | $ 2,708,704 |
| Intangible assets | 26,802 | 5,698 | 32,500 | 2,709 | 19,207 | — | 21,916 | — | 54,416 |
| Total Assets held for sale | 3,860 | 20,067 | 23,927 | — | — | — | — | — | 23,927 |
| Total assets | 1,492,144 | 116,922 | 1,609,066 | 285,517 | 460,209 | 923,981 | 1,669,707 | 193,784 | 3,472,557 |
| Capital expenditures | 46,885 | 2,631 | 49,516 | 28,566 | 23,743 | 56,552 | 108,861 | — | 158,377 |
| Acquisition of operating entities | 2,083 | — | 2,083 | 27,545 | — | 209,386 | 236,931 | — | 239,014 |

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 25. Segmented information (continued)

### Operational segments (continued)

| | Year ended December 31, 2012 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Algonquin Power | | | Liberty Utilities | | | | Corporate | Total |
| | Renewable Energy | Thermal Energy | Total | Central | West | East | Total | | |
| **Revenue** | | | | | | | | | |
| Regulated electricity sales and distribution | $ — | $ — | $ — | $ — | $ 71,734 | $ 36,723 | $ 108,457 | $ — | $ 108,457 |
| Regulated gas sales and distribution | — | — | — | 25,802 | — | 49,916 | 75,718 | — | 75,718 |
| Regulated water reclamation and distribution | — | — | — | 9,127 | 37,296 | — | 46,423 | — | 46,423 |
| Non-regulated energy sales | 84,236 | 30,115 | 114,351 | — | — | — | — | — | 114,351 |
| Other revenue | 1,925 | 1,686 | 3,611 | — | 152 | 94 | 246 | — | 3,857 |
| Total revenue | 86,161 | 31,801 | 117,962 | 34,929 | 109,182 | 86,733 | 230,844 | — | 348,806 |
| **Operating expenses** | 30,308 | 8,568 | 38,876 | 13,096 | 35,645 | 30,209 | 78,950 | — | 117,826 |
| **Regulated electricity purchased** | — | — | — | — | 43,861 | 24,348 | 68,209 | — | 68,209 |
| **Regulated gas purchased** | — | — | — | 13,648 | — | 23,813 | 37,461 | — | 37,461 |
| **Non-regulated fuel for generation** | — | 14,589 | 14,589 | — | — | — | — | — | 14,589 |
| | 55,853 | 8,644 | 64,497 | 8,185 | 29,676 | 8,363 | 46,224 | — | 110,721 |
| Depreciation of property, plant and equipment | (18,823) | (4,782) | (23,605) | (3,333) | (11,120) | (7,129) | (21,582) | — | (45,187) |
| Amortization of intangible assets | (2,653) | (831) | (3,484) | (81) | (586) | — | (667) | — | (4,151) |
| Administration expenses | (9,424) | (2,176) | (11,600) | 294 | (4,091) | (1,223) | (5,020) | (2,952) | (19,572) |
| Foreign exchange gain | — | — | — | — | — | — | — | 561 | 561 |
| Interest expense | (15,060) | (1,733) | (16,793) | (96) | (8,066) | (694) | (8,856) | (9,971) | (35,620) |
| Interest, dividend and other income | 2,038 | 509 | 2,547 | — | 2,113 | 461 | 2,574 | 2,118 | 7,239 |
| Acquisition related costs | (3,155) | 21 | (3,134) | (1,442) | — | (3,112) | (4,554) | — | (7,688) |
| Gain/(loss) on derivative financial instruments | (2,954) | — | (2,954) | — | — | — | — | 3,187 | 233 |
| Earnings from continuing operations before income taxes | 5,822 | (348) | 5,474 | 3,527 | 7,926 | (3,334) | 8,119 | (7,057) | 6,536 |
| Loss from discontinued operations before income taxes | (1,925) | 3,022 | 1,097 | — | — | — | — | — | 1,097 |
| Earnings/(loss) before income taxes | $ 3,897 | $ 2,674 | $ 6,571 | $ 3,527 | $ 7,926 | $ (3,334) | $ 8,119 | $ (7,057) | $ 7,633 |
| Property, plant and equipment | $1,157,062 | $ 77,438 | $1,234,500 | $ 151,637 | $350,053 | $350,088 | $ 851,778 | $ — | $ 2,086,278 |
| Intangible assets | 29,480 | 6,132 | 35,612 | 2,613 | 18,556 | — | 21,169 | — | 56,781 |
| Total Assets held for sale | 24,390 | 78,947 | 103,337 | — | — | — | — | — | 103,337 |
| Total assets | 1,272,037 | 175,926 | 1,447,963 | 212,495 | 464,201 | 500,374 | 1,177,070 | 153,957 | 2,778,990 |
| Capital expenditures | 21,068 | 10,348 | 31,416 | 10,777 | 23,181 | 12,488 | 46,446 | 67 | 77,929 |
| Acquisition of operating entities | 245,718 | — | 245,718 | 128,890 | — | 295,297 | 424,187 | — | 669,905 |

*(in thousands of Canadian dollars except as noted and amounts per share)*

**25. Segmented information (continued)**

**Operational segments (continued)**

**Operational segments (continued)**

The majority of non-regulated energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2013 or 2012: Hydro Québec 14% (2012 - 17%), Manitoba Hydro 14% (2012 – 20%), and California PG&E 9% (2012 - 10%). The Company has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

APUC and its subsidiaries operate in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

| | 2013 | 2012 |
|---|---|---|
| Revenue | | |
| Canada | $ 65,380 | $ 62,036 |
| United States | 609,911 | 286,770 |
| | $ 675,291 | $ 348,806 |
| Property, plant and equipment | | |
| Canada | $ 433,153 | $ 395,896 |
| United States | 2,275,551 | 1,690,382 |
| | $ 2,708,704 | $ 2,086,278 |
| Intangible assets | | |
| Canada | $ 26,802 | $ 29,480 |
| United States | 27,614 | 27,301 |
| | $ 54,416 | $ 56,781 |

Revenues are attributed to the two countries based on the location of the underlying generating and utility facilities.

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 26. Financial instruments

(a) Fair value of financial instruments

| 2013 | Carrying amount | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| Notes receivable | $ 22,678 | $ 26,321 | $ — | $ — | $ 26,321 |
| Derivative financial instruments: | | | | | |
| Energy contracts designated as a cashflow hedge | 31,971 | 31,971 | — | — | 31,971 |
| Energy contracts not designated as a cashflow hedge | 3,737 | 3,737 | — | — | 3,737 |
| Cross-currency swap designated as a foreign exchange hedge | 109 | 109 | — | 109 | — |
| Commodity contracts for regulated operations | 482 | 482 | — | 482 | — |
| Total derivative financial instruments | 36,299 | 36,299 | — | 591 | 35,708 |
| Total financial assets | $ 58,977 | $ 62,620 | $ — | $ 591 | $ 62,029 |
| Long-term liabilities | $ 1,255,588 | $ 1,261,340 | $ 296,986 | $ 964,354 | $ — |
| Derivative financial instruments: | | | | | |
| Energy contracts designated as a cashflow hedge | 4,781 | 4,781 | — | — | 4,781 |
| Cross-currency swap designated as a foreign exchange hedge | 7,947 | 7,947 | — | 7,947 | — |
| Interest rate swaps not designated as a hedge | 3,180 | 3,180 | — | 3,180 | — |
| Commodity contracts for regulated operations | 313 | 313 | — | 313 | — |
| Total derivative financial instruments | 16,221 | 16,221 | — | 11,440 | 4,781 |
| Total financial liabilities | $ 1,271,809 | $ 1,277,561 | $ 296,986 | $ 975,794 | $ 4,781 |

*(in thousands of Canadian dollars except as noted and amounts per share)*

**26. Financial instruments (continued)**

(a) Fair value of financial instruments (continued)

| 2012 | Carrying amount | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| Notes receivable | $ 22,757 | $ 25,476 | $ — | $ — | $ 25,476 |
| Derivative financial instruments: | | | | | |
| Energy contracts designated as a cashflow hedge | 12,695 | 12,695 | — | — | 12,695 |
| Cross-currency swap designated as a foreign exchange hedge | 408 | 408 | — | 408 | — |
| Commodity contracts for regulatory operations | 147 | 147 | — | 147 | — |
| Total derivative financial instruments | 13,250 | 13,250 | — | 555 | 12,695 |
| Total financial assets | $ 36,007 | $ 38,726 | $ — | $ 555 | $ 38,171 |
| Long-term liabilities | $ 770,826 | $ 785,473 | $ 293,348 | $ 492,125 | $ — |
| Convertible debentures | 960 | 1,319 | 1,319 | — | — |
| Derivative financial instruments: | | | | | |
| Energy contracts designated as a cashflow hedge | 9,012 | 9,012 | — | — | 9,012 |
| Cross-currency swap designated as a foreign exchange hedge | 2,078 | 2,078 | — | 2,078 | — |
| Interest rate swaps not designated as a hedge | 4,778 | 4,778 | — | 4,778 | — |
| Energy derivative contracts | 287 | 287 | — | — | 287 |
| Commodity contracts for regulated operations | 1,661 | 1,661 | — | 1,661 | — |
| Total derivative financial instruments | 17,816 | 17,816 | — | 8,517 | 9,299 |
| Total financial liabilities | $ 789,602 | $ 804,608 | $ 294,667 | $ 500,642 | $ 9,299 |

**26. Financial instruments (continued)**

(a) Fair value of financial instruments (continued)

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value (a level 2 measurement) at December 31, 2013 and 2012 due to the short-term maturity of these instruments.

Notes receivable fair values have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management. Such estimate is significantly influenced by unobservable data and therefore this fair value is subject to estimation risk.

APUC has long-term liabilities at fixed interest rates and variable rates. The estimated fair value is calculated using current interest rates. The fair value of convertible debentures is determined using quoted market price.

The Company's Level 2 fair value derivative instruments primarily consist of swaps, options, and forward physical deals where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace.

The Red Lily conversion option is measured at fair value on a recurring basis using unobservable inputs (Level 3). The fair value is based on an income approach using an option pricing model that includes various inputs such as energy yield function from wind, estimated cash flows and a discount rate of 8.5%. The Company used a discount rate believed to be most relevant given the business strategy. There was no change in fair value of $nil during the years ended December 31, 2013 or 2012.

The Company's Level 3 instruments consist of energy contracts for energy sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from USD $21.5 to $181 as of December 31, 2013. The processes and methods of measurement are developed using the market knowledge of the trading operations within the Company and are derived from observable energy curves adjusted to reflect the illiquid market of the hedges and, in some cases, the variability in deliverable energy. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement. The change in the fair value of the energy contracts are detailed in notes 26(b)(ii) and 26(b)(iv).

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the years ended December 31, 2013 or 2012.

(b) Derivative instruments

Derivative instruments are recognized on the balance sheet as either assets or liabilities and measured at fair value each reporting period.

(i) Commodity derivatives – regulated accounting

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with its regulated gas service territories. The Company's strategy is to minimize fluctuations in gas sales prices to regulated customers. The accounting for these derivative instruments is subject to current guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the accompanying balance sheets. Gains or losses on the settlement of these contracts are included in the calculation of deferred gas costs (note 7 (d)).

*(in thousands of Canadian dollars except as noted and amounts per share)*

**26. Financial instruments (continued)**

(b) Derivative instruments (continued)

(i) Commodity derivatives – regulated accounting (continued)

The following are commodity volumes, in dekatherms ("dths") associated with the above derivative contracts:

| | **2013** |
|---|---|
| Financial contracts: Gas swaps | 2,734,304 |
| Gas options | 2,082,104 |
| | 4,816,408 |

The change in fair value of the derivative instruments is recorded as an offsetting adjustment to regulatory assets and liabilities. As a result, the changes in fair value of these natural gas derivative contracts and their offsetting adjustment to regulatory assets and liabilities had no earnings impact. The following table presents the impact of the change in the fair value of the Company's natural gas derivative contracts had on the accompanying balance sheets:

| | **2013** | **2012** |
|---|---|---|
| Regulatory assets: | | |
| Gas swap contracts | $ 86 | $ 1,555 |
| Gas option contracts | $ 208 | $ 106 |
| Regulatory liabilities: | | |
| Gas swap contracts | $ 416 | $ 90 |
| Gas option contracts | $ 37 | $ 57 |

(ii) Cash flow hedges

APCo reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities and at one of its hydro facilities no longer subject to a power purchase agreement by entering into the following long-term energy derivative contracts.

| **Notional quantity (MW-hrs)** | **Expiry** | **Receive average prices (per MW-hr)** | | **Pay floating price (per MW-hr)** |
|---|---|---|---|---|
| Energy delivered less existing swap | December 2014 | U.S. $ | 32.64 | PJM Western HUB |
| Energy delivered less existing swap | December 2014 | U.S. $ | 25.64 | NI HUB |
| Energy delivered less existing swap | December 2014 | U.S. $ | 27.39 | ERCOT North HUB |
| 147,199 | December 2016 | $ | 67.36 | AESO |
| 1,029,732 | December 2022 | U.S. $ | 42.81 | PJM Western HUB |
| 4,395,665 | December 2022 | U.S. $ | 30.25 | NI HUB |
| 4,663,097 | December 2027 | U.S. $ | 36.46 | ERCOT North HUB |

As at December 31, 2013, an amount receivable under the derivatives for Sandy Ridge, Senate and Minonk Wind Facilities of $7,344 (2012 - $nil) was held as collateral by the counterparty.

The effects on the consolidated statements of operations of derivative financial instruments designated as cash flow hedge consist of the following:

| | **2013** | **2012** |
|---|---|---|
| Gain on derivative instruments (ineffective portion) | $ 1,304 | $ 105 |

*(in thousands of Canadian dollars except as noted and amounts per share)*

**26. Financial instruments (continued)**

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

The following table summarizes changes in other comprehensive income attributable to derivative financial instruments designated as a hedge:

| | 2013 | 2012 |
|---|---|---|
| Effective portion of cash flow hedge, gain | $ 17,338 | $ 5,217 |
| Gain (loss) realized on cash flow hedge | (30) | (49) |
| | $ 17,308 | $ 5,168 |
| Less noncontrolling interest | (9,064) | (1,572) |
| Change in fair value of cash flow hedge in other comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp. | $ 8,244 | $ 3,596 |

The Company expects $4,949 of unrealized gains currently in accumulated other comprehensive loss to be reclassified into net earnings within the next twelve months, as the underlying hedged transactions settle.

(iii) Foreign exchange hedge of net investment in foreign operation

The Company periodically uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from the U.S. operations. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

Concurrent with its $150,000 debentures offering in December 2012, APCo entered into a cross currency swap, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. APCo designated the entire notional amount of the cross currency fixed for fixed interest rate swap and related short-term USD payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in APCo's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the USD accruals that are designated as, and are effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in other comprehensive income) related to the net investment. A foreign currency loss of $5,771 was recorded in other comprehensive income in 2013.

(iv) Other derivatives

APCo provides energy requirements to various customers under contracts at fixed rates. While the production from the Tinker Assets are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

This risk is mitigated though the use of short term financial forward energy purchase contracts which are classified as derivative instruments. The electricity derivative contracts are net settled fixed-for-floating swaps whereby APUC pays a fixed price and receives the floating or indexed price on a notional quantity of energy over the remainder of the contract term at an average rate, as per the following table. These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

| Notional quantity (MW-hrs) | Expiry | Receive average prices (per MW-hr) | Net Asset |
|---|---|---|---|
| 19,440 | February 2014 | U.S. $ 61.40 | $ 1,833 |
| 69,154 | March 2015 | U.S. $ 48.83 | 1,729 |

*(in thousands of Canadian dollars except as noted and amounts per share)*

**26. Financial instruments (continued)**

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

For derivatives that are not designated as cash flow hedges, and for the ineffective portion of gains and losses on derivatives that are accounted as hedges the changes in the fair value are immediately recognized in earnings.

The effects on the statement of operations of derivative financial instruments not designated as hedges consist of the following:

| | 2013 | 2012 |
|---|---|---|
| Change in unrealized loss/(gain) on derivative financial instruments: | | |
| Interest rate swaps | $ (1,598) | $ (2,197) |
| Energy derivative contracts | (3,809) | (825) |
| Total change in unrealized loss/(gain) on derivative financial instruments | $ (5,407) | $ (3,022) |
| Realized loss/(gain) on derivative financial instruments: | | |
| Foreign exchange contracts | $ — | $ (187) |
| Interest rate swaps | 2,024 | 2,094 |
| Energy derivative contracts | (466) | 987 |
| Total realized loss on derivative financial instruments | $ 1,558 | $ 2,894 |
| Loss/(gain) on derivative financial instruments accounted for as hedges | $ (3,849) | $ (128) |
| Ineffective portion of derivatives financial instruments accounted for as hedges | $ (1,351) | (105) |
| Gain on derivative financial instruments | $ (5,200) | $ (233) |

(c) Risk management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view to mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk, liquidity risk, foreign currency risk and interest rate risk, and how the Company manages those risks.

*Credit risk*

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents accounts receivable and notes receivable. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders in Canada all of which have a credit rating of A or better. The Company does not consider the risk associated with accounts receivable to be significant as over 80% of revenue from power generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

*(in thousands of Canadian dollars except as noted and amounts per share)*

**26. Financial instruments (continued)**

(c) Risk management (continued)

The remaining revenue is primarily earned by the Utility Services business unit which consists of water and wastewater utilities, electric utilities and gas utilities in the United States. In this regard, the credit risk related to Utility Services accounts receivable balances of U.S. $101,867 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition the state regulators of the Company's utilities allow for a reasonable bad debt expense to be incorporated in the rates and therefore ultimately recoverable from rate payers.

As at December 31, 2013 the Company's maximum exposure to credit risk for these financial instruments was as follows:

| | December 31, 2013 | |
|---|---|---|
| | Canadian $ | US $ |
| Cash and cash equivalents and restricted cash | $ 3,465 | $ 15,415 |
| Accounts receivable | 18,948 | 137,481 |
| Allowance for Doubtful Accounts | — | (7,955) |
| Notes Receivable | 20,529 | 2,021 |
| | $ 42,942 | $ 146,962 |

In addition, the Company continuously monitors the creditworthiness of the counterparties to its foreign exchange, interest rate, and energy derivative contracts prior to settlement, and assess each counterparty's ability to perform on the transactions set forth in the contracts.

*Liquidity risk*

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As at December 31, 2013, in addition to cash on hand of $13,839 the Company had $202,665 available to be drawn on its senior debt facilities. The senior credit facilities contain covenants which may limit amounts available to be drawn.

*(in thousands of Canadian dollars except as noted and amounts per share)*

## 26. Financial instruments (continued)

(c) Risk management (continued)

The Company's liabilities mature as follows:

| | Due less than 1 year | Due 2 to 3 years | Due 4 to 5 years | Due after 5 years | Total |
|---|---|---|---|---|---|
| Long term debt obligations | $ 8,339 | $ 147,076 | $ 171,907 | $ 928,266 | $ 1,255,588 |
| Advances in aid of construction | 1,239 | | — | 77,697 | 78,936 |
| Interest on long term debt | 54,804 | 103,605 | 89,966 | 168,448 | 416,823 |
| Purchase Obligations | 156,905 | | — | — | 156,905 |
| Environmental obligation | 10,111 | 45,158 | 3,912 | 18,548 | 77,729 |
| Derivative financial instruments: | | | | | |
| Cross- currency swap | — | — | — | 7,947 | 7,947 |
| Interest rate swaps | 1,936 | 1,244 | — | — | 3,180 |
| Energy derivative and commodity contracts | 240 | 72 | — | 4,465 | 4,777 |
| Capital lease payments | 125 | 3,919 | — | — | 4,044 |
| Other obligations | 7,326 | — | — | 13,809 | 21,135 |
| Total obligations | $ 241,025 | $ 301,074 | $ 265,785 | $1,219,180 | $ 2,027,064 |

*Foreign currency risk*

The Company is exposed to currency fluctuations from its U.S. based operations. APUC manages this risk primarily through the use of natural hedges by using U.S. long term debt to finance its U.S. operations.

APCo designates the amounts drawn on its bank credit facility denominated in U.S. dollars as a hedge of the foreign currency exposure of its net investment in APCo's U.S. operations. The foreign currency transaction gain or loss on the outstanding U.S. dollar denominated balance of APCo's facility that is designated a hedge of the net investment in its foreign operations is reported in the same manner as a translation adjustment (in other comprehensive income) related to the net investment, to the extent it is effective as a hedge. A foreign currency loss of $1,607 was recorded in other comprehensive income.

*Interest rate risk*

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, including certain project specific debt and its revolving credit facility, its interest rate swaps as well as interest earned on its cash on hand. The Company does not currently hedge that risk.

APCo is party to an interest rate swap whereby, the Company pays a fixed interest rate of 4.47% on a notional amount of $62,706 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. At December 31, 2013, the estimated fair value of the interest rate swap was a liability of $3,180 (2012 – liability of $4,778). This interest rate swap is not being accounted for as a hedge and consequently, changes in fair value are recorded in earnings as they occur.

## 27. Comparative figures

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted in the current year.

# CORPORATE INFORMATION

## DIRECTORS

**Kenneth Moore, Chairman** – Managing Partner, NewPoint Capital Partners Inc.
**Christopher Ball** – Executive Vice-President, Corpfinance International Ltd.
**Christopher Huskilson** – President & Chief Executive Officer, Emera Inc.
**Chris Jarratt** – Vice-Chair, Algonquin Power & Utilities Corp.
**Ian Robertson** – Chief Executive Officer, Algonquin Power & Utilities Corp.
**George Steeves** – Principal, True North Energy

## THE MANAGEMENT GROUP

**Ian Robertson**, Chief Executive Officer
**Chris Jarratt**, Vice-Chair
**David Bronicheski**, Chief Financial Officer

## HEAD OFFICE

2845 Bristol Circle
Oakville, Ontario
Canada L6H 7H7
Telephone – 905-465-4500
Fax – 905-465-4514
Website – www.algonquinpowerandutilities.com

## REGISTRAR AND TRANSFER AGENT

CST Trust Company
320 Bay Street
Toronto, Ontario
Canada M5H 4A6

## AUDITORS

Ernst & Young LLP
Toronto, Ontario

## STOCK EXCHANGE

The Toronto Stock Exchange:
AQN, AQN.PR.A, AQN.PR.D

## LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Toronto, Ontario


2845 Bristol Circle
Oakville, Ontario
Canada L6H 7H7

Tel: 905-465-4500
Fax: 905-465-4514

www.algonquinpowerandutilities.com

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